THE EFFECTS OF WELL AND RESERVOIR PARAMETERS ON HORIZONTAL AND VERTICAL WELLS PERFORMANCE IN GAS CONDENSATE RESERVOIR

BY

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DEDICATION

This effort is dedicated to:

My mother

My brother

My sisters

My wife and children

My country

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First and foremost thanks to Allah for giving me strength, patience and ability to accomplish this research.

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ABSTRACT

Name: **SALEM OBAID OMAR BAARIMAH**

Title: **The Effects of Well and Reservoir Parameters on Horizontal and Vertical Wells Performance in Gas Condensate Reservoir**

Major Field: **Petroleum Engineering**

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Predicting the effects of reservoir and well parameters on the performance of horizontal and vertical wells in retrograde gas-condensate reservoirs is important in determining the well type needed in a given formation. Due to increased number of horizontal wells drilled in retrograde gas-condensate reservoirs, there is a necessity for better and improved understanding of the behavior and performance of this type of wells in retrograde gas-condensate reservoirs.

The purpose of this research study is to investigate the effects of reservoir and well parameters on the performance of horizontal and vertical wells in volumetric retrograde gas-condensate reservoirs using three-dimensional, single-well compositional reservoir simulation model. To simulate the depletion processes, the single-well compositional reservoir simulation model is used to investigate the effects of reservoir and well parameters such as horizontal permeability, reservoir thickness, ratio of vertical to horizontal permeability (k_v/k_h), and horizontal well penetration ratio on the performance of horizontal and vertical wells.

Results indicate that, for the vertical well, the lower the values of horizontal permeability and formation thickness, the higher the average reservoir pressure at abandonment time. For the horizontal well, the lower the values of formation permeability, formation thickness, k_v/k_h ratio, and horizontal well penetration ratio, the higher the average reservoir pressure at abandonment time. The lower the values of horizontal permeability and formation thickness, and the higher the value of k_v/k_h and horizontal well penetration ratio, the better the performance of horizontal well over the performance of vertical well.

Simple algebraic equations are presented that can be used to calculate the abandonment time as a function of well and reservoir parameters. Results presented in tabular form can be used by reservoir engineers in order to select the appropriate well type in a given reservoir, to determine the recovery factors for gross-gas, free-gas and oil, and to determine the abandonment pressure and abandonment time.

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ملخص الرسالة

الاســــــــــــم: **ســالم عبيد عـمـر باعــارمـــه**

عنوان الرســـالة: **تأثير المتغيرات البئرية والمكمنية على ادائية الآبار الافقية و العمودية في مكمن الغاز المكثف**

التخـــــــــصص: **هندسة البترول**

تاريخ الرســـالة: **مايو 2012م**

التنبؤ لتأثير المتغيرات البئرية والمكمنية على ادائية الآبار الافقية و العمودية في مكمن الغاز المكثف مهم جدا لتحديد نوع البئر المناسب للمكمن المحدد .ايضا نظرا لزيادة الآبار الافقية المحفورة في مكامن الغازات المكثفة فهناك ضروره ملحه لفهم ادائية وسلوك مثل هذه الآبار.

الهدف من هذه الدراسة البحثية هو التحقق من تاثير المتغيرات البئرية والمكمنية على ادائية الآبار الافقية و العمودية في مكمن الغاز المكثف الحجمي باستخدام نموذج المحاكى العددي الثلاثي الابعاد باستخدام نموذج البئر الاحادي .

المتغيرات البئرية والمكمنية التي تم دراستها تشمل تأثير طول الجزء الافقي للبئرالافقي ، سمك التكوين، النفاذية الافقية، مساحة وشكل المكمن ونسبه النفاذية العمودية الى الافقية.

تشير النتائج الى ان البئرالعمودي ذات اقل قيمه في النفاذية العمودية والسمك يمتلك اعلى قيمه في معدل الضغط المكمني عند زمن الترك. ونفس الملاحظة بالنسبه للبئر الافقي عند اقل قيمه في النفاذية العمودية، السمك، نسبه النفاذية العمودية الى الافقية وطول الجزء الافقي من البئر.

ايضا تم انشاء معادله رياضه بسيطه لمعرفه زمن الترك للبئر اعتمادا على المتغيرات المكمنية.جميع نتائج البحث وضعت في جدوال حتى يتمكن لمهندسي المكامن استخدامها لتحديد البئر المناسب، معدلات الاسترداد للغاز والنفط اضافة الى زمن ترك البئر.

درجة الماجستير في العلوم

جامعة الملك فهد للبترول والمعادن

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CHAPTER 1

INTRODUCTION

1.1 Background

Considerable gas reserves can be found in retrograde gas-condensate reservoirs. A retrograde gas-condensate reservoir contains a single-phase fluid at original reservoir conditions when the initial pressure is above the dew-point pressure of the fluid. It consists mostly of methane and other short chain hydrocarbons, but it also contains long chain hydrocarbons, termed heavy ends. Under certain conditions of temperature, pressure and the composition of the fluid, a liquid phase (called a retrograde condensate) will be formed in the reservoir. As a reservoir is produced, formation temperature usually doesn't change, but pressure decreases. The largest pressure drop occurs near production wells. When the pressure in a retrograde gas-condensate reservoir decreases to a certain point, called the saturation pressure or dew–point, a liquid phase rich in heavy ends drops out of solution; the gas phase is slightly depleted of heavy ends. In other words, a liquid phase forms in retrograde gas-condensate reservoirs when the reservoir pressure decreases below dew–point pressure. Figure 1.1 presents the pressure-temperature diagram for retrograde gas-condensate reservoirs.

The initial producing gas-oil ratio, the gravity of the stock-tank liquid, and the color of the stock-tank liquid are the field parameters that can be used in order to determine the reservoir fluid type. Retrograde gas-condensate reservoirs demonstrate a lower GOR limit of 3300 SCF/STB and an upper GOR limit of 150000 SCF/STB, stock-tank liquid gravities between 40° and 60° API, and stock-tank liquid being lightly colored, orange, brown, greenish, or transparent.

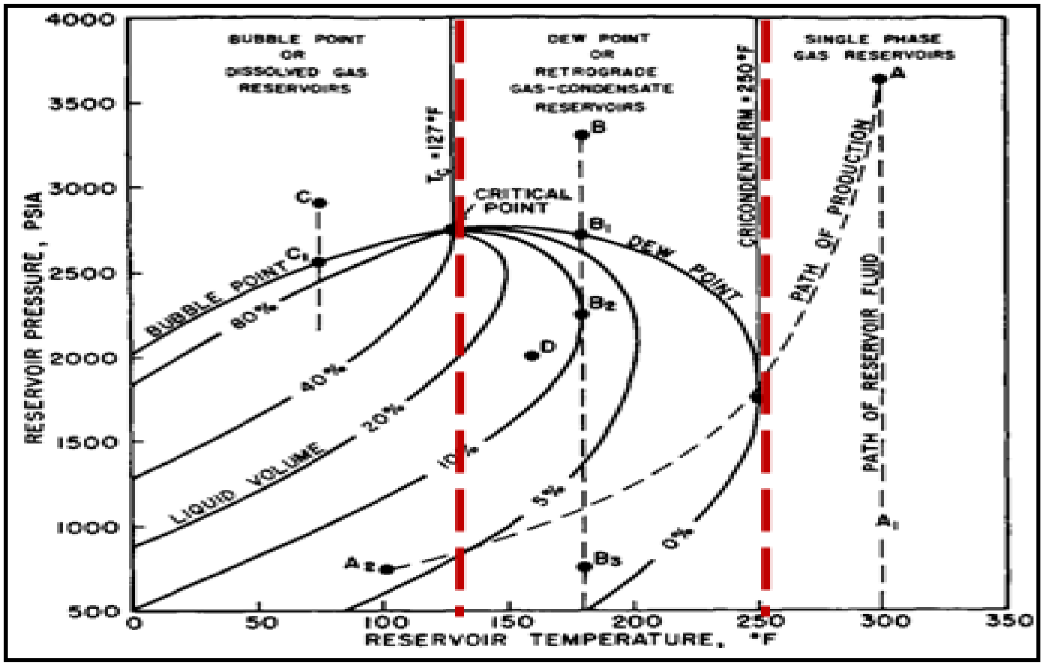

Figure 1.1 Pressure-temperature phase diagram of a reservoir fluid[1]

Fluid flow in retrograde gas-condensate reservoirs can be divided into three reservoir regions, although in some situations not all three are present. The two regions closest to a well can exist when flowing bottom-hole pressure is below the dew point of the fluid. The third region, away from producing wells, exists only when the average reservoir pressure is above the dew–point. This third region includes most of the reservoir away from producing wells. Since the reservoir pressure of the third region is above the dew point pressure, there is only a single phase hydrocarbon gas present in this region. In the second region, the condensate-buildup region, liquid drops out of the gas phase, but its saturation remains low enough that it is immobile; there is still single-phase gas flow. In the first region closest to a producing well, the liquid saturation increases and the condensate saturation here is greater than the critical condensate saturation. In this case, both gas and condensate liquid phases flow toward the wellbore. Figures 1.2 and 1.3 present condensate saturation below dew–point pressure in the three regions described above.

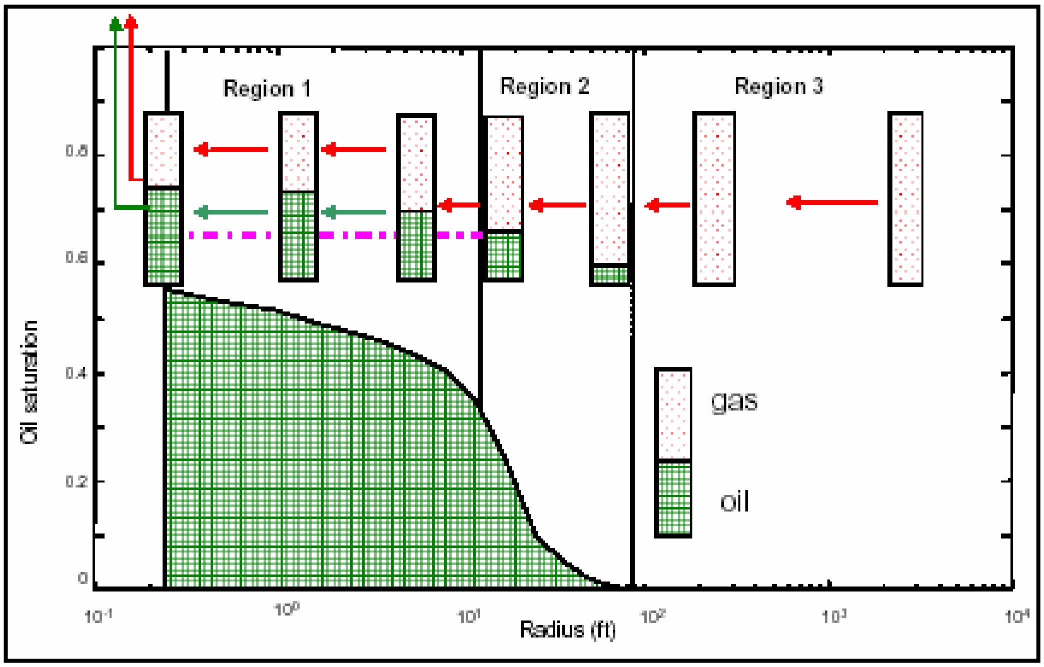

Figure 1.2 Schematic gas-condensate flow behaviors below dew point pressure[2]

The main difference between retrograde gas-condensate and dry gas reservoirs is condensate blockage. In retrograde gas-condensate reservoirs, condensate blockage occurs due to the formation of liquid phase around the wellbore as pressure decreases below dew–point pressure. As a result, production performance can decrease dramatically if these condensate banking effects are not understood at the start of field development. In addition, condensate blockage near the well may cause a significant loss in well deliverability for low-to-moderate permeability reservoirs. Figure 1.4 presents condensate blockage due to the formation of liquid phase around the wellbore.

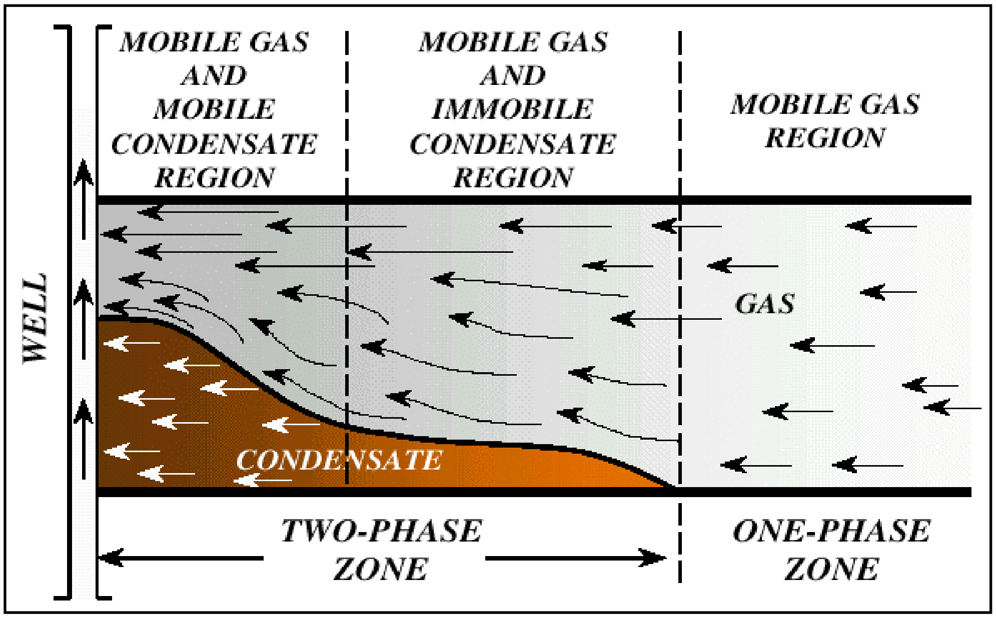

Figure 1.3 Condensate saturation flow behavior below dew point pressure[3]

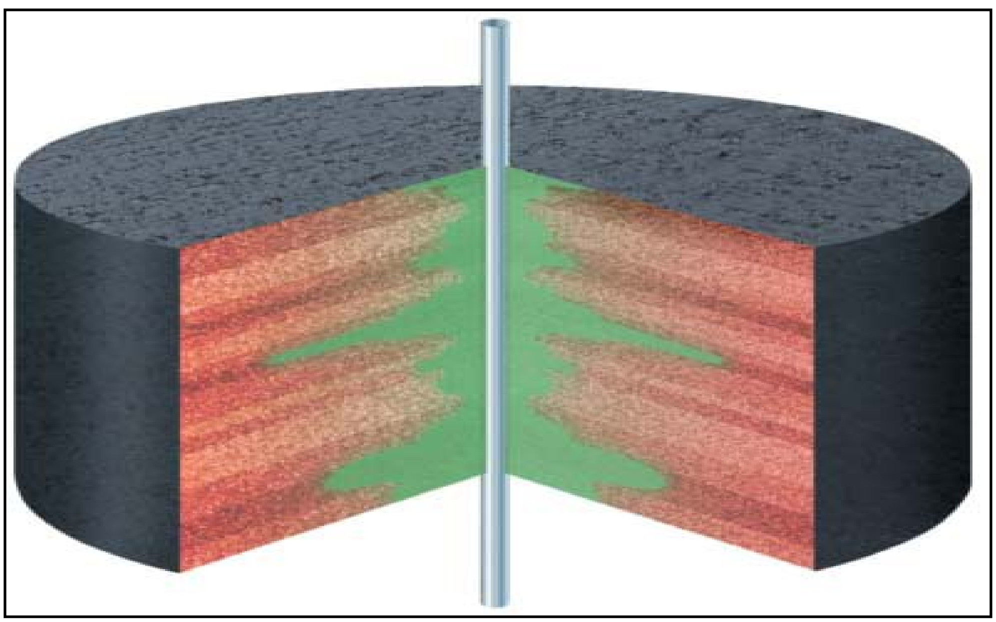

Figure 1.4 Condensate blockage near the well

There is a great potential to develop retrograde gas-condensate reservoirs with horizontal wells, particularly in low-permeability reservoirs. In the last few years, many horizontal wells have been drilled around the world. The major purpose of horizontal wells is to enhance reservoir contact and thereby enhance well productivity. Productivity of a horizontal well depends upon well and reservoir parameters. Horizontal well length depends upon the drilling technique that is used to drill the well. The major disadvantage of horizontal wells is their cost. Typically, the drilling and completion cost of a horizontal well is about 1.2 to1.5 times more than a vertical well, depending upon drilling method and the completion technique employed. While horizontal wells are generally more expensive to drill than vertical wells, they often reduce the total number of wells required in a reservoir that is a good candidate for horizontal well application. To determine if horizontal wells are appropriate in a particular reservoir an incremental economic analysis must be performed. In order to do this we must be able to estimate the investment and forecast future production for the well.

Once reservoir fluids enter a wellbore, both temperature and pressure conditions may change. Condensate liquid can be produced into the wellbore, but condensate liquid can also drop out within the wellbore because of changes in pressure and temperature conditions. If the gas does not have sufficient energy to carry the liquid to surface, liquid loading or fallback in the wellbore occurs because the liquid is denser than the gas phase traveling along with it. If the liquid falls back down the wellbore, the liquid saturation near the wellbore will increase. This will reduce the productivity of a well by a factor of two or more. This phenomenon, called condensate blockage or condensate banking, results from a combination of factors, including fluid phase properties, formation flow characteristics and pressures in the formation and in the wellbore. Various solutions have been implemented in order to decrease or to postpone the adverse effect of condensate blockage on productivity. These include hydraulic fracturing, wettability alteration, and unconventional wells. One of these solutions includes drilling horizontal wells instead of vertical wells to reduce the effects of condensate blockage or condensate banking on productivity of wells.

Due to the composition and phase changes of light components that occur during reservoir depletion, there is a great need for a quick and reliable method or models to estimate the horizontal and vertical wells performance in retrograde gas-condensate reservoirs. In addition, quantifying the effects of well and reservoir parameters on the performance of horizontal and vertical wells in gas condensate reservoirs is very important to decide what type well to utilize in a given reservoir. A reservoir simulation model is typically used for this task. Reservoir simulation is defined as the combination of principles of physics, mathematics, reservoir engineering and computer programming in order to develop a tool for predicting hydrocarbon-reservoir performance under various operating conditions.

During production in retrograde gas-condensate reservoirs, the fluid changes its overall composition in both time and space and, therefore, multiphase flow may exist in the reservoir as described above. The relationship between pressure drop and flow rate, which controls well deliverability, is complicated in producing gas condensate reservoirs due to the existence of inertial or 'non-Darcy flow' effects and high capillary number effects in the near-wellbore region. Therefore, one needs to utilize a reservoir simulator in order to model the complex compositional and phase changes that occur in a gas-condensate reservoir during production.

Accurate laboratory studies of PVT and phase equilibrium behavior of reservoir fluids are necessary for characterizing these fluids and for evaluating their volumetric depletion performance as reservoir pressure decreases due to production. Fluid properties obtained from the analysis of constant-composition expansion laboratory tests performed on a reservoir fluid sample from a retrograde gas-condensate reservoir are needed as part of the input data for a compositional reservoir simulation study.

1.2 Statement of the Problem

The decline of reservoir pressure below the dew-point pressure in retrograde gas-condensate reservoirs leads to the buildup of a liquid condensate phase in the reservoir, including the area near the wellbore, resulting in condensate blockage or condensate banking. To decrease or to postpone the adverse effect of condensate blockage on productivity, several methods have been suggested. One of these methods is the use of horizontal wells instead of vertical wells in order to reduce the effects of condensate blockage or condensate banking on productivity of wells.

The performance of horizontal wells in retrograde gas-condensate reservoirs and the recovery factor of the so-called initial oil and gas in place for all well and reservoir parameters have previously not been quantified and generalized based on dimensionless parameters that are dependent on various well and reservoir parameters. In addition, simple algebraic equations describing the performance of horizontal and vertical wells based on reservoir simulation studies for various well and reservoir parameters are not available.

1.3 Research Objectives

The most accurate and realistic mathematical model for the description of reservoir fluid flow when there are composition and phase changes in the reservoir is the compositional reservoir simulation model. Therefore, the main objective of this research is to conduct compositional reservoir simulation studies in order to determine the effects of all relevant well and reservoir parameters on the performance of horizontal and vertical wells in retrograde gas-condensate reservoirs. Fluid properties obtained from constant-composition expansion laboratory test on a real sample obtained from a retrograde gas-condensate reservoir will be utilized in this compositional reservoir simulation study. The main reservoir parameters that will be investigated include:

- The influence of the length of the horizontal section of the well.
- The influence of the reservoir thickness.
- The influence of the horizontal formation permeability.
- The influence of drainage area size and shape.
- The influence of the vertical to horizontal permeability ratio (k_v/k_h).

The following results will be used to evaluate and to compare the performance of the wells as a function of time:

- Gas production rate and cumulative gas production.
- Oil production rate and cumulative oil production.
- Oil and gas recovery factors.
- The time to reach the dew-point pressure and the economic limit.

The simple, algebraic equations that will be developed can be used to quickly calculate the abandonment time as a function of well and reservoir parameters without the future use of numerical reservoir simulation. Results will be presented in tabular form can be used by reservoir engineers in order to select the appropriate well type in a given reservoir.

CHAPTER 2

Literature Review

Several studies have examined the various factors that influence the behavior of retrograde gas-condensate reservoirs. There are also several reservoir simulation studies on the performance of vertical wells in gas-condensate reservoirs. Moreover, numerous authors have investigated the phenomenon of a rapid loss of productivity of vertical wells in retrograde gas-condensate wells.

Fussel[4] (1973) described the use of a modified version of the one-dimensional radial model developed by Roebuck et al. He also studied the effect of condensate accumulation on well productivity and evaluated the applicability of steady-state method similar to the one presented by O'Dell and Miller[5] (1967). He concluded that the productivity of a retrograde gas-condensate well is much higher than the productivity predicted by the O'Dell and Miller[29] due to the fact that the method by O'Dell and Miller does not predict the saturation profile in the two-phase region correctly.

AI-Majed [6] (1991) developed a variable cell model for simulating gas condensate reservoir performance .The model was used to study the effect of liquid flow on well-stream fluid composition. Also, the influence of reservoir fluid phase equilibrium data on the extent of two phase flow dominated region was investigated.

Fevang[7] (1995) showed that, when reservoir pressure around a well drops below the dew-point pressure, retrograde condensation occurs and three regions with different liquid saturations are formed. Away from the well, an outer region has the initial liquid saturation. There is an intermediate region with a rapid increase in liquid saturation and a corresponding decrease in gas relative permeability. Liquid in that region is less than the critical condensate saturation and hence is immobile. Closer to the well an inner region forms where the liquid saturation reaches a critical value and the effluent travels as two-phase flow with constant composition.

Settari et al[8] (1996) conducted a study on the effect of condensate blockage on productivity index of hydraulically-fractured wells in a complex, highly heterogeneous reservoir containing rich gas condensate. Their study, using a 2-component black oil simulation model, was performed on the Smorbukk field, offshore Norway. They found that proppant fracturing was effective in mitigating the effect of condensate blockage on well productivity; the effectiveness depended primarily on the reservoir heterogeneity, fracture length and fracture conductivity.

AL-shaidi[9] (1997) modeled the flow of gas-condensate fluids in porous media with emphasis on near-wellbore conditions. He used results from theoretical, empirical as well as simulation studies in order to improve the present technology on the treatment of the flow of retrograde gas-condensate in reservoirs.

Adel and Salah[10] (1997) presented two general regression neural network models. The first model is developed to predict dew-point pressure and gas compressibility at dew-point using initial compositions of numerous samples while the second model is developed to predict the changes in well-stream effluent composition at any stage of pressure depletion. They showed that these models can be used to forecast constant-volume depletion (CVD) needed for reservoir and production engineering calculations such as material balance calculations, reservoir simulations, separator design, and vertical performance calculations, to check the accuracy of constant-volume depletion tests, and to reduce time and money involved in simulations.

Muladi and Pinczewski[11] (1999) analyzed the effects of the layering on horizontal well performance in retrograde gas-condensate reservoirs. Four cases of different reservoir heterogenities were studied using an 11-layer reservoir. For each case, three prediction runs were made for average permeability values of 1 md, 10 md, and 100 md. The following criteria were used to compare the relative performance of the different cases studied: production rate, cumulative production, and flowing bottom hole pressure of the well. They concluded that horizontal wells have better performance in cases of high average permeability of the reservoir when compared with the performance of vertical wells.

Hashmi [12] (2000) studied the effect of a hydrulic fracture on the performance of a layered retrograde gas-condensate reservoir using a compositional simulator. He compared the condensate saturation distribution before and after the fracturing around the wellbore. He investigated the effect of fracture length and fracture conductivity on long-term productivity. Moreover, the effect of flow rate on the performance of fractured gas-condensate reservoir was investigated. He determined the optimum fracture parametes for the system considered.

El-Banbi and McCain[13] (2000) used Compositional simulation to investigate the productivity of gas-condensate wells. They made the following conclusions: - (a) production rate of gas-condensate wells in low-permeability reservoirs declines because of liquid drop-out around the wellbore when the near-wellbore pressure drops below the dew point pressure, (b) condensate builds up in the reservoir as the reservoir pressure drops below the dew-point pressure; as a result, the gas moving to the wellbore becomes leaner, (c) the gas production rate may stabilize, or possibly increase, after the period of initial decline, (d) both the liquid and gas around the wellbore change in composition and the liquid becomes heavier and the gas becomes leaner, and (e) viscosity of the liquid increases and viscosity of the gas decreases with production. This improves the mobility of the gas with respect to the oil.

Gringarten et al[14] (2000) also found that when reservoir pressure around a well drops below the dew-point pressure, retrograde condensation occurs and three regions are created with different liquid saturations. Away from the well, an outer region has the initial liquid saturation. There is an intermediate region with a rapid increase in gas relative permeability; liquid in that region is immobile. Closer to the well, an inner region forms where the liquid saturation reaches a critical value, and the effluent travels as a two phase flow with constant composition (the condensate that is deposited as pressure is decreased is equal to that which flows towards the well). There may also exist a fourth region in the immediate vicinity of the well where low interfacial tensions at high rates yield a decrease of the liquid saturation and an increase of the gas relative permeability.

Dehane et al[15] (2000) investigated the performance of horizontal wells and vertical wells in retrograde gas-condensate reservoirs under various depletion schemes and they investigated drawdown pressure of horizontal wells and vertical wells in retrograde gas-condensate reservoirs. They used reservoir simulation to study the effect of drain-hole section and reservoir thickness on horizontal well productivity and condensate recovery. They concluded that the pressure drawdown is smaller for a horizontal well (for different drain hole lengths) than that for a vertical well; the problems related to the liquid drop-out can be reduced by the use of horizontal wells. In addition, the reservoir thickness has a large effect on condensate recovery and pressure drawdown (less pressure drawdown occurs in thick formations and consequently more liquid is recovered). Moreover, layers with high values of kh contain the most liquid accumulation. Liquid saturation around a vertical well can reach a value of 15 % and that for a horizontal well does not exceed 6 % for the same production rate and after the same period of production.

Fevang and Whitson[16](2000) provided specific guidelines for choosing the PVT model, black-oil or equation of state (EOS), for full-field reservoir simulation of volatile/near-critical oil and gas-condensate fluid systems produced by depletion and/or gas injection. They concluded that a black-oil model is always adequate for simulating depletion performance of petroleum reservoirs if: (a) solution GOR and solution OGR are initialized properly, and (b) the PVT data are generated properly. A compositional simulation model is generally recommended for gas injection studies. For gas injection, a black-oil model can only be used in: (a) oil reservoirs when there is minimal vaporization, and (b) lean to medium-rich gas-condensate reservoirs undergoing cycling above the dew-point for retrograde gas-condensate fluids. Initial fluids-in-place can be calculated accurately for pseudoized-EOS and black-oil models by initializing with the correct compositional gradient.

Humoud [17] (2001) evaluated the existing gas-condensate dew-point pressure correlations using unpublished, experimentally-obtained PVT fluid data representing

Middle East retrograde gas-condensate reservoirs. He then developed a new, empirical dew-point pressure correlation. The new correlation depended only on readily-available fluid properties normally measured in the field. Multiple linear/nonlinear least-squares regression analysis were used a new empirical dew-point pressure correlation. Different statistical error analyses were utilized to evaluate the new correlation against the exisiting empirical correlations.

Mott[18] (2002) presented a new and simpler technique for forecasting performance of retrograde gas-condensate wells, which can be performed in a spreadsheet. He used a material balance model for reservoir depletion and a two-phase pseudo-pressure integral for well inflow performance. The pseudo-pressure integral technique was extended to include high-velocity effects and also to allow for the change in produced fluid composition due to the formation of the condensate bank. He tested the new technique by comparison with the results of fine-grid compositional simulation, and the results were in good agreement for a wide range of cases covering vertical, horizontal and hydraulically-fractured wells.

Jan et al[19] (2003) addressed two of the possible factors that may have caused the dependency of relative permeability on flow rates, namely interfacial tension and permeability distribution. They measured a series of two-phase relative permeability curves from near-critical fluid by means of steady-state technique. They concluded that the relative permeability of retrograde gas-condensate is a strong function of interfacial tension. They also found that permeability distribution has significant effect on rate-sensitive retrograde gas-condensate relative permeability. A higher degree of permeability distribution heterogeneity results in larger rate-sensitive effect.

Lal [20] (2003) investigated the factors that lead to such high saturation buildup in multiphase flow behavior in retrograde gas-condensate reservoirs. Also, changes in the fluid composition due to liquid drop-out have also been investigated. He studied the effect of critical condensate saturation and shapes of relative permeability curves on flow and saturation buildup of the fluid.

Maravi [21] (2003) developed two new Vogel-type inflow performance relations (or IPR) correlations for retrograde gas-condensate reservoir systems. One correlation predicts dry gas production and the other predicts condensate (liquid) production. These correlations provide a relationship between reservoir rock and fluid properties (dew-point, temperature, and end-point relative permeabilities, composition, etc.) and the flow rate-pressure performance for the reservoir system. The proposed IPR relationships for compositional reservoir systems are based on data from over 3000 compositional reservoir simulation cases developed using various fluid properties and relative permeability curves.

Izgec[22] (2003) investigated the performance of a modified black-oil model for a rich retrograde gas-condensate reservoir under natural depletion and gas cycling scenarios. He performed simulations for natural depletion and gas cycling scenarios for a rich retrograde gas-condensate reservoir with full compositional and modified black-oil (MBO) models. Modified black-oil simulation results were evaluated by comparison with results from the fully compositional simulation. Almost all the cases showed differences in condensate saturation distribution around the wellbore area and the entire reservoir. The MBO model indicated the runs with the horizontal wells exhibited closer performances with compositional model compared to the runs with vertical wells. The minimum difference between the models is 5 % in terms of average field oil saturation and this was obtained for gas injection with the reduced vertical communication.

Wilson [23] (2003) used an empirical model for gas mobility to provide a concept for predicting well performance behavior in a retrograde gas-condensate reservoir. The proposed model predicts the behavior of the gas permeability (or mobility) function in the reservoir as condensate evolves and the gas permeability is reduced in the near-wellbore region due to the "condensate bank". The proposed model is based on the observations of simulated reservoir performance and predicts the behavior of the gas permeability over time and radial distance.

Rostami[24] (2004) studied the effect of retrograde gas-condensate damage in hydraulically-fractured wells and investigated the condensate damage at the face of the hydraulic fracture in transient and boundary-dominated periods when the effects of reservoir depletion are taken into account. As a first step, simulation of liquid flow into the fracture was performed using a 2D, 1-phase simulator in order to better understand the results of retrograde gas-condensate simulation. He concluded that the optimum drawdown corresponds to the lowest bottom hole pressure (BHP) giving the largest cumulative gas production at any time. The condensate damage does not prevent the lowest drawdown, BHP= 1,000 psi, from producing the highest cumulative gas.

Xiao and Al-Muraikhi[25] (2004) presented a new calculation method to calculate retrograde gas-condensate well production deliverability without the use of reservoir simulators. The new method models condensate banking by considering the combinational effects of condensate dropout (PVT effect) and condensate accumulation (relative permeability behavior). They found that the proposed method generates well production profiles and production gas-oil ratios with engineering accuracy for unstimulated vertical wells, hydraulically-fractured vertical wells, and horizontal wells. They concluded that the method can be used as a rapid tool to assess various factors affecting retrograde gas-condensate well productivity such as formation permeability, relative permeability, fluid type, well type and high rate effects.

Hashemi and Gringarten[26] (2005) used reservoir simulation to compare productivity of vertical, horizontal and hydraulically fractured wells in retrograde gas-condensate reservoirs. They found that horizontal wells and hydraulically fractured vertical wells improve well productivity. The degree of productivity enhancement, however, depends on well and reservoir parameters such as horizontal well lengths, permeability anisotropy, fracture length, and fracture conductivity. They concluded that the well test data can be used to calibrate the parameters of empirical correlation in well performance models when experimental data are not available.

Whitson and Kuntadi[27] (2005) addressed some key reservoir and production issues related to gas and condensate recovery from Khuff reservoirs in the Middle East – namely Ghawar Khuff, North Field and South Pars. They concluded that the key parameters determining production performance include: (a) well kh, (b) well initial gas-in-place, (c) stimulation skin, (d) minimum (tubing) pressure constraint, (e) magnitude of condensate blockage, and (f) sealing barriers. They also found that parameters that do not have a significant impact on production performance include: (a) aquifer size, (b) vertical-to-horizontal permeability ratio k_v/k_h, (c) heterogeneity (permeability distribution) of low-k rock, and (d) PVT formulation.

Marir and Tiab[28] (2006) studied the performance of horizontal wells in a Sector-Model, to predict their behavior in regards to water production and condensate recovery. To simulate the depletion processes, they used compositional simulation to investigate the following phenomena in the case of horizontal and vertical wells: (a) water influx effects, (b) comparison of horizontal well drawdown pressure to that of vertical wells, and (c) the influence of the horizontal well length section and reservoir thickness on horizontal well productivity and condensate recovery. They concluded that the use of horizontal wells is a proven technology for reducing water influx problems and for delaying water breakthrough and that the pressure drawdown for a horizontal well in a gas-condensate reservoir (for different drain-hole lengths) is smaller than that for a vertical well.

Jamiolahmady et al[29] (2007) investigated the performances of vertical, slanted, and horizontal wells productivity in layered, retrograde gas-condensate reservoirs. They used compositional reservoir simulation to conduct a series of sensitivity analysis on a single-well model. Also, the effects of relative permeability, fluid properties, and reservoir anisotropy (k_v/k_h) were studied. They concluded the following:

a) For homogenous systems, a horizontal (highly-slanted) well (HW) or a slanted well (SW) have higher productivities; the improvement due to increase in lateral reach is less pronounced at lower k_v/k_h values especially for slanted well.

b) In heterogeneous system, the horizontal or highly-slanted well improved the flow performance by reaching its total production plateau faster than vertical well. The performance of the slanted well, on the other hand, is adversely affected by the extended crossflow from low-permeability to high-permeability layers.

c) The impact of k_v/k_h on production is more pronounced for slanted well, than for the vertical well and finally for the horizontal (highly-slanted) well especially at lower k_v/k_h ratio. Hence, the preference of having horizontal (highly-slanted) well is economically more defendable at lower k_v/k_h.

Miller et al[30] (2010) studied the application of horizontal wells in a giant retrograde gas-condensate reservoir (North Field- Qatar) to reduce the condensate blockage. Their objective was to detemine the fraction of increased gas production in a horizontal well due to increased formation contact and due to the reduction in condensate blockage. They concluded that horizontal well has a smaller drawdown pressure than a vertical well. This smaller drawdown pressure in the horizontal well leads to a delayed dew-point pressure being reached compared with the vertical well. They also found that oil saturation buildup in the near wellbore is 1.35 times lower in the horizontal well than in the vertical well and that the ratio of horizontal well productivity index to vertical well productivity index is 3.38 before the dew-point pressure is reached while it is 6.11 after the dew-point pressure is reached.

By conducting compositional reservoir simulation studies, Emmanuel et al[31] (2010) investigated the best modes of retrograde gas-condensate reservoir operation that will improve the total recovery of the condensate. They concluded that the initial recovery was 22.5% for primary production without injection and that there was a remarkable improvement in the recovery factor by injecting fluids for pressure maintenance. Recovery factor was 36.5% for water injection, 85.7% for CO_2 injection, 81.4% for N_2 injection, and 83.5% for combination of CO_2 and N_2 injection.

Ghahri et al[32](2011) conducted a sensitivity study to evaluate the impact of a number of pertinent parameters on the deviated and horizontal well productivity. They also concluded that as in horizontal wells (HWs), productivity ratio (PR) of deviated wells (DWs) strongly depends on gas total ratio (GTRw) and velocity. At low velocities and for the same DW length as that of the vertical well (VW), they concluded the following: (a) PR increases for all GTRw, as the deviation angle increases , in the cases with moderate gas condensate fluid, (b) PR with methane is higher than those without methane, (c) PR is almost independent of methane effect for the DW with deviation angle less than 60^0, (d) PR increases slightly when GTRw varies between of 0.7 and 0.95, and sharply as GTRw approaches to 1 due to the more pronounced effect of the inertia in vertical wells(VWs), (e) at the same GTRw, PR increases with increasing velocity due to the more pronounced effect of inertia in VWs.

Sureshjani and Gerami[33](2011) developed a new material-balance-time and boundary-dominated-flow equation for gas-condensate reservoirs. They were coupled with an appropriate material-balance equation to build a production model for analyzing production data. The proposed model is able to accurately estimate average reservoir pressure and gas in place of a gas/condensate reservoir. They also concluded that ignoring dependency of relative permeability on velocity in the proposed model provides acceptable estimates of initial gas in place.

CHAPTER 3

RESEARCH METHODOLOGY

Retrograde gas-condensate reservoirs exhibit a complex thermodynamic behavior that can not be described by simple pressure-dependent functional relations. Compositions change continuously during production by pressure depletion or by cycling above and below dew-point pressures. A simulator is a program used to perform material balance calculations to determine pressure and saturation distribution of the reservoir as a function of time. Reservoir simulation models are commonly used to predict the performance of retrograde gas-condensate reservoirs. The models incorporate rock and fluid properties and are used to predict the dynamic influence of condensate blockage on gas and condensate production.

The ECLIPSE simulator suite consists of two separate simulators: ECLIPSE 100 specializing in black oil modeling, and ECLIPSE 300 specializing in compositional modeling. ECLIPSE 100 is a fully-implicit, three phase, three dimensional, general purpose black oil simulator with gas condensate options, while ECLIPSE 300 is a compositional simulator with cubic equation of state, pressure dependent K-value and black oil fluid treatments. ECLIPSE 300 can be run in fully implicit, IMPES and adaptive implicit (AIM) modes.

A compositional reservoir simulator is used to model the complex compositional changes and phase behavior which occur in retrograde gas-condensate reservoirs during production. The compositional model gives increased accuracy by utilizing a more realistic description of the fluid. The compositional simulation models assume that reservoir fluid properties are dependent not only upon the reservoir temperature and pressure but also on the composition of the reservoir fluid which changes during production, either by depletion or by gas injection.

The compositional model represents the hydrocarbon phases as multi-component mixtures and there are no restrictions in mutual solubilities; that is, any component may exist in the gas or the oil phase. The fundamental difference between compositional reservoir simulation models and the black-oil reservoir simution models lies in their treatment of fluid properties and phase behavior. Compositional models are used when recovery processes are sensitive to compositional changes. These situations include primary depletion of volatile-oil and gas-condensate reservoirs, as well as pressure maintenance operations for these reservoirs. In addition, multiple-contact miscible processes are generally modeled with compositional simulators.

The compositional model incorporates compressibility, compositional effects, and mass interchange between phases. It consists of Darcy's law for volumetric flow velocities, mass balance for hydrocarbon components, thermodynamic equilibrium for mass interchange between phases, and an equation of state for phase saturations. Although the mathematical equations are more complicated than the ones in black-oil reservoir simulation models, the compositional reservoir simulation models simply model the three-phase Darcy flow, the movement of each individual hydrocarbon component, and the phase equilibrium at each point in the reservoir.

The compositional reservoir simulation model assumes equilibrium at all times when two phases are present and this equilibrium determines the corresponding oil and gas saturations. According to this assumption, the rate of mass transfer of components between phases are much greater than the rate at which individual components travel within the phases themselves. The equilibrium between oil and gas phases is determined by a flash calculation from thermodynamic flash calculations using an equation-of-state or from correlated or empirically-derived equilibrium ratios or K-values. An equation of state (EOS) is a mathematical expression relating volume, pressure, temperature, composition and can be used to describe the volumetric and phase behavior of hydrocarbon mixtures. Additionally, equations of state provide an efficient way to describe the volumetric and phase behavior of hydrocarbon mixtures. Once the EOS is tuned to match the experimental data of the given fluid, it is assumed that it will represent the phase behavior of that fluid at any pressure and temperature.

Due to the above reasons, this research will use a compositional reservoir simulation model in order to predict the performance of horizontal and vertical wells in gas-condensate reservoirs for various well and reservoir parameters.

This is a process where all information for describing the reservoir is provided to the reservoir simulator as input data. An ECLIPSE data input file is divided into sections, each of which is introduced by a keyword. In this study , the input data are categorized and need to be entered under six (6) sections in the input data-file. The names of the sections are in a required sequence namely: RUNSPEC, GRID, PROPS, SOLUTION, SUMMARY and the SCHEDULE sections.

• RUNSPEC:

The data specified in this section is used to determine the amount of storage required by the run and includes the units, phases present, number of grid cell, number of PVT and relative K tables, maximum number of wells and start date for the run.

• GRID SECTION:

Here the amount of data that needs to be specified in this section is usually very large for full field stimulation study. It is where property values from the maps are placed on the grid. This data includes cell dimension, the depth of each cell, gross thickness, net thickness, porosity and permeability.

• PROPS SECTION:

The simulator requires this section, and it contains data primarily measured in the laboratory and normally specified as tables. This includes: oil, water and gas at stock tank conditions, relative permeability curves, capillary pressure data and rock compressibility.

• SOLUTION:

This section is used by the simulator to take the first time-step (model initialization). Here pressure and saturations for each grid cell is needed.

• SUMMARY SECTION:

Specification of data to be written to the summary file after each time step. It is necessary if certain types of graphical output (for example water-cut as a function of time) are to be generated after the run has finished. If this section is omitted no Summary files are created.

• SCHEDULE

Specifies the operations to be simulated (production and injection controls and constraints) and the times at which output reports are required. Vertical flow performance curves and simulator tuning parameters may also be specified in the SCHEDULE section.

CHAPTER 4

MODEL DESCRIPTION

The Eclipse 300 compositional simulator was used for simulation. The three-parameter Peng-Robinson equation of state was used to simulate the PVT properties of the retrograde gas-condensate fluid. Simulation was carried out for two cases, one with constant rate of production and the other with constant bottom hole flowing pressure as the mode of production. The results are presented for both of these cases.

4.1 Reservoir Model Description

In this study we used a synthetic reservoir model that includes the fluid description of a real gas condensate. This synthetic reservoir model of a single layer homogenous reservoir was generated under the following assumptions:

- Square and rectangular drainage area shapes with a finite drainage area size.
- Reservoir thickness is uniform throughout the reservoir.
- Homogeneous and anisotropic reservoir. The permeability in the x and y directions are equal and is different from the vertical permeability.
- The vertical well is completed and perforated through the entire formation thickness. The horizontal well is either open hole or perforated through the entire horizontal section of the wellbore.
- No gas solubility in the water.

- No reaction between the reservoir fluid and reservoir rock.
- Phase equilibrium is accurately calculated by the equation of state (EOS).
- A reduced permeability zone (skin) is not considered.
- The water phase is immobile.

Two drainage area sizes were considered: 80 and 160 acres. Formation thicknesses of 25, 50 and 100 ft, 20% porosity, and three horizontal permeabilities: 1, 10 and 100 md were considered. Vertical to horizontal permeability ratio (k_v/k_h) of 1, 0.5 and 1 were considered. The top of the model is at a depth of 12000 ft with an initial pressure of 5868 psia. Reservoir properties and range of the well and reservoir parameters considered in this study are shown in Table 4.1.

Table 4.1 Reservoir and fluid properties

Reservoir area	acres	80 – 160
Reservoir thickness	ft	25 – 50 – 100
Reservoir top	ft	12000
Reservoir porosity	%	20
horizontal permeabilities	md	1 – 10 – 100
k_v/k_h		1 – 0.5 – 0.1
Initial reservoir pressure	psia	5868
Dew point pressure	psia	5680
Initial reservoir temperature	°F	254
Initial oil saturation (S_o)	%	0
Initial water saturation (S_w)	%	16
Initial gas saturation (S_g)	%	84
Vertical well radius (r_w)	ft	0.3
Horizontal well radius (r_w)	ft	0.3
$L_H/2Xe$		0.2 – 0.4 – 0.8
Rock Compressibility	1/psia	$4*10^{-6}$
Water compressibility	1/psia	0.000003
Water FVF	RB/STB	1.0
Oil density	lbs/ft^3	48.1
Water density	lbs/ft^3	63.0
Gas density	lbs/ft^3	0.061
Water viscosity	cp	0.31

4.2 Well Model Description

Two well models were developed for this study; a vertical well model and a horizontal well model. The vertical well was modeled in radial and Cartesian coordinates while the horizontal well was modeled in Cartesian coordinates. The 3D radial model was used for the vertical well. A single-well producer was placed at the center of the reservoir and is assumed to be perforated across the entire thickness of the reservoir. For the horizontal well, a 3D square and rectangular Cartesian grid system were used. The well was centered in the drainage volume. We used different grid models for different well geometries; Table 4.2 shows the number of grids for each reservoir drainage area size (Cartesian grid system), while the number of grids for radial grid system is shown in Table 4.3. The length of the horizontal well (L_H) is illustrated in Table 4.4.

Table 4.2 Cartesian grid system

Cartesian grid system			
A= 80 acres, square drainage area	A= 160 acres, square drainage area	A= 80 acres, rectangular drainage area	A= 160 acres, rectangular drainage area
NX=NY=34	NX=NY=48	NX=48	NX=55
NZ=4	NZ=4	NY=24	NY=34
		NZ=4	NZ=4

Table 4.3 Radial grid system

Radial grid system	
A= 80 acres	A= 160 acres
0.3 – 0.7 – 1 – 5 – 10 – 20	0.3 – 0.7 – 1 – 5 – 10 – 20
40 – 60 – 80 – 100 – 1130	40 – 60 – 80 – 100 – 120
160 – 160 – 200 – 250	140 – 170 – 200 – 240 – 300

Table 4.4 Length of the horizontal well L_H

Length of the horizontal well L_H, ft			
A= 80 acres, square drainage area	A= 160 acres, square drainage area	A= 80 acres, rectangular drainage area	A= 160 acres, rectangular drainage area
374	528	528	748
748	1056	1056	1496
1496	2112	2112	2992

Figure 4.1 illustrates 3D simulation Cartesian grid system model reservoir for horizontal well while Figure 4.2 demonstrates 3D simulation horizontal well model. The 3D simulation radial grid system model for vertical well is showed in Figure 4.3 whereas Figure 4.4 shows 3D simulation vertical well model.

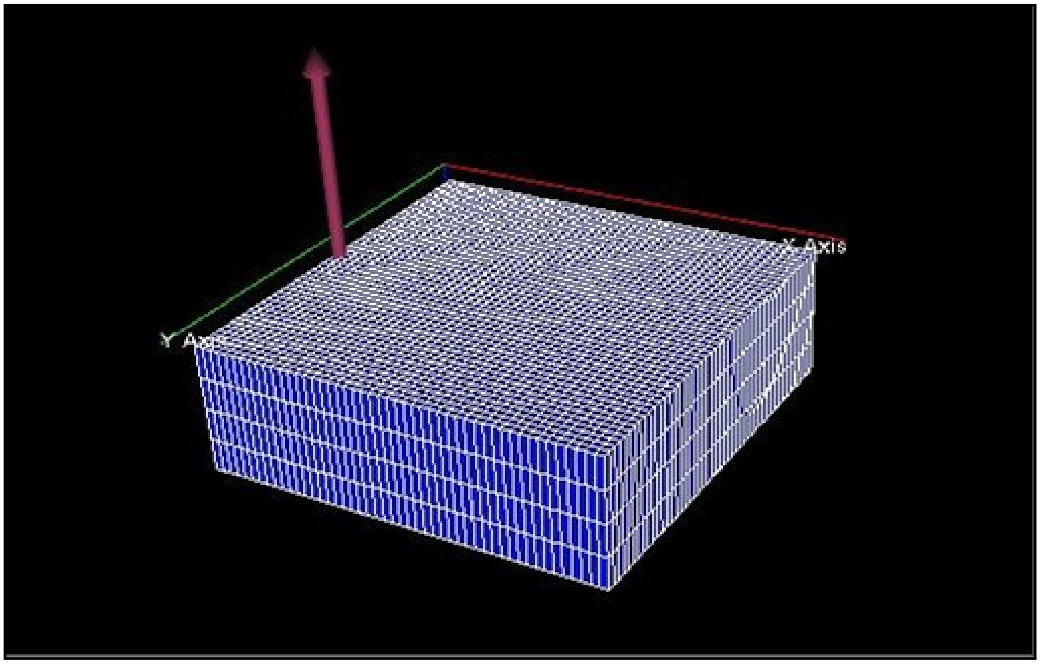

Figure 4.1 Schematic 3D reservoir simulation model for horizontal well

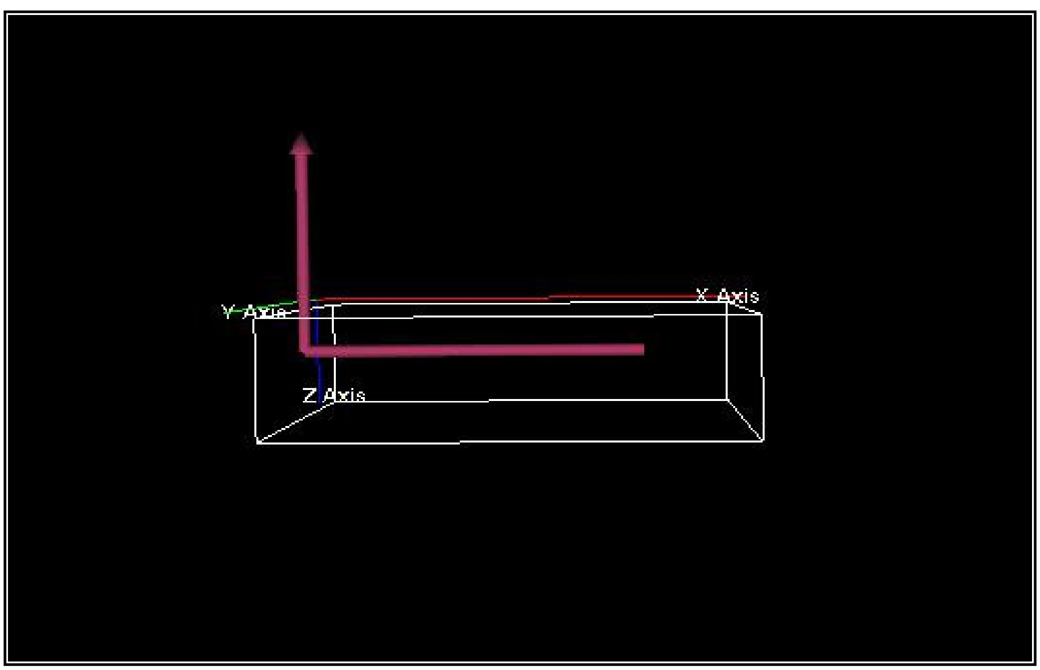

Figure 4.2 Schematic horizontal well model

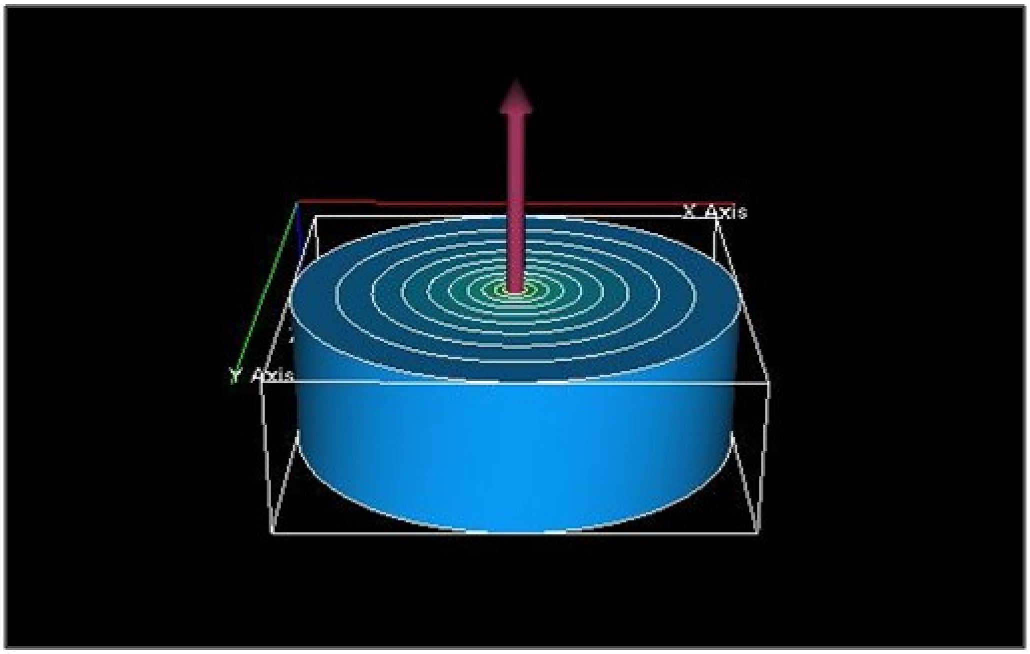

Figure 4.3 Schematic 3D reservoir simulation model for vertical well

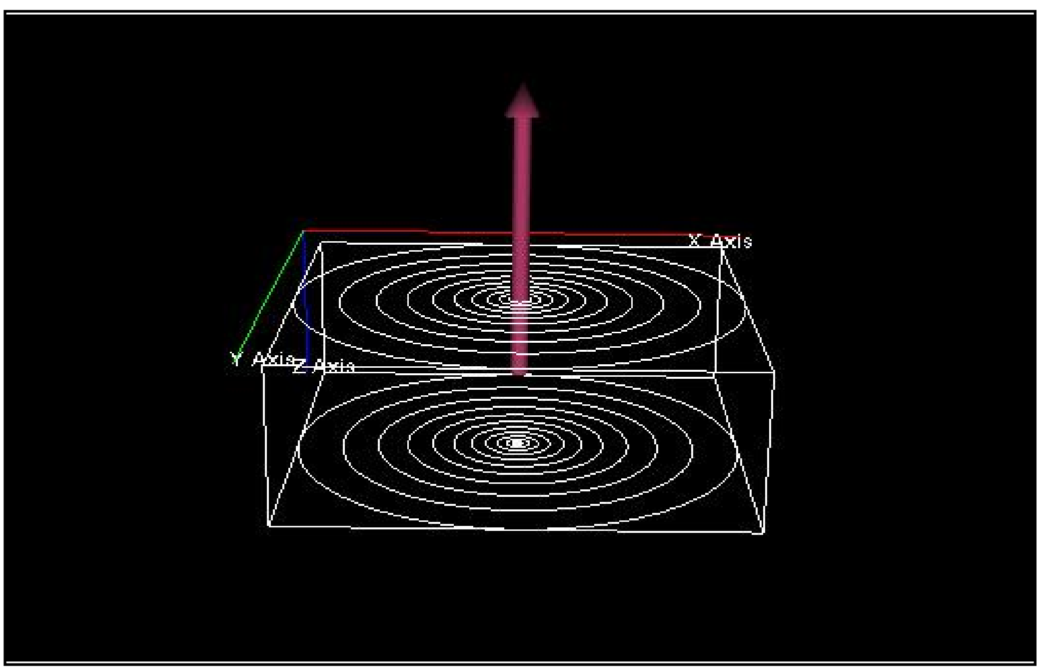

Figure 4.4 Schematic vertical well model

4.3 Fluid Properties Model Description

The fluid selected for our study is a very rich gas condensate taken from Cusiana Field located 125 miles northeast of Bogotá, Colombia in the Llanos basin. Data was taken from Izgec[22] and Maravi[21]. Sampling conditions are presented in Table 4.5

Table 4.5 Sampling conditions

Choke	(1/64")	24
Well Head Pressure	Psia	2270
Well Head Temperature	°F	124
Separator Pressure	Psia	313
Separator Temperature	°F	84
Oil Rate	STB/D	870
Oil Density	°API	42.1
Gas Oil Ratio (GOR)	SCF/STB	5855
Gas Specific Gravity		0.716

A constant composition expansion (CCE) test and a separator test were used to characterize the fluid. A compositional analysis with hydrocarbon components that includes a heavy fraction of $C30^+$ and a set of experimental data are presented in Table 4.6.

Table 4.6 Cusiana mixture extended composition

Component	Mole Fraction (Zi)	Molecular weight (Mi)	$MiZi$
N_2	0.0052	28.013	0.1457
CO_2	0.0457	44.01	2.0113
C_1	0.6897	16.043	11.065
C_2	0.0889	30.07	2.6732
C_3	0.0418	44.097	1.8433
IC_4	0.0099	58.124	0.5754
NC_4	0.014	58.124	0.8137
IC_5	0.0071	72.151	0.5123
NC_5	0.006	72.151	0.4329
C_6	0.0099	86.178	0.8532
C_7	0.0102	96	0.9792
C_8	0.0128	107	1.3696
C_9	0.0097	121	1.1737
C_{10}	0.0073	134	0.9782
C_{11}	0.0053	147	0.7791
C_{12}	0.0044	161	0.7084
C_{13}	0.0048	175	0.84
C_{14}	0.0041	190	0.779
C_{15}	0.0036	206	0.7416
C_{16}	0.0028	222	0.6216
C_{17}	0.0026	237	0.6162
C_{18}	0.0024	251	0.6024
C_{19}	0.0019	263	0.4997
C_{20}	0.0016	275	0.44
C_{21}	0.0013	291	0.3783
C_{22}	0.0011	300	0.33
C_{23}	0.001	312	0.312
C_{24}	0.0008	324	0.2592
C_{25}	0.0007	337	0.2359
C_{26}	0.0006	349	0.2094
C_{27}	0.0006	360	0.216
C_{28}	0.0005	372	0.186
C_{29}	0.0004	382	0.1528
C_{30}^{+}	0.0013	394	0.5122

The relative volume was obtained from the constant composition expansion at 254°F is presented in Table 4.7. Figure 4.5 illustrates experimental and simulated relative volume data from CCE at 254 °F. Table 4.8 shows additional data from a separator test.

Table 4.7 Constant composition expansion data

Pressure, psia	Relative Volume
6358	0.9612
6255	0.9665
6157	0.9716
6055	0.9773
5959	0.9830
5892	0.9869
5842	0.9898
5794	0.9927
5744	0.9958
5695	0.9990
Pd=5680	1.000
5644	1.0030
5545	1.0100
5446	1.0190
5347	1.0280
5254	1.0370
5056	1.0570
4740	1.0930
4437	1.1360
4144	1.1870
3847	1.2490
3544	1.3280
3241	1.4260
2937	1.550
2660	1.6940
2351	1.9010
2044	2.1790
1738	2.5680
1435	3.1240
1133	4.0040

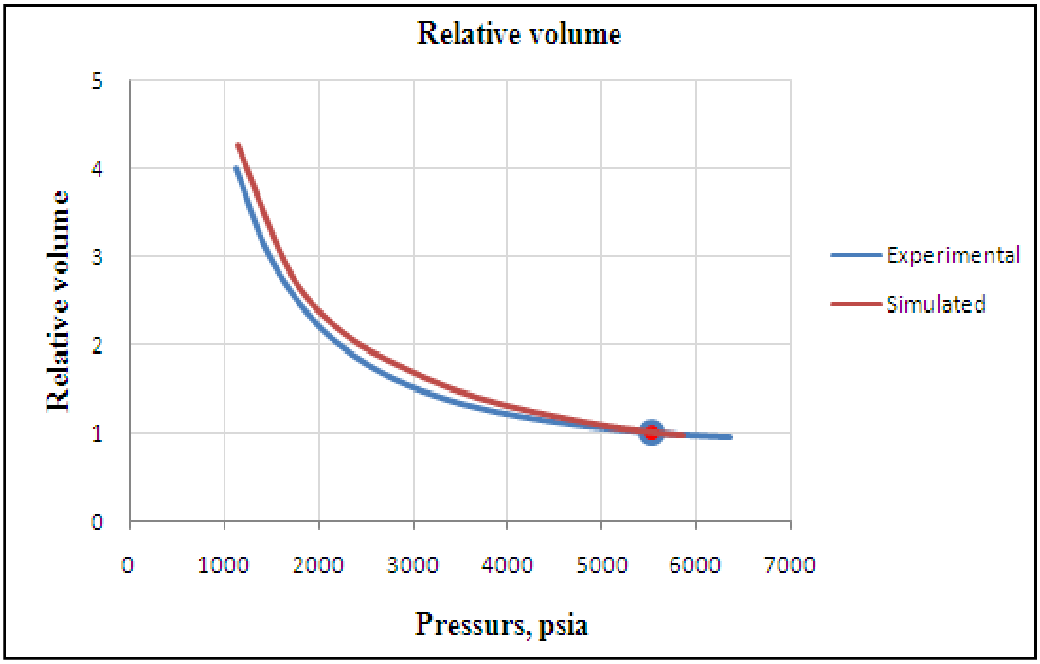

Figure 4.5 Experimental and simulated relative volume data from CCE at 254 °F

Table 4.8 Separator test data

Pressure, psig	Temperature,°F	Gas Oil Ratio, SCF/STB	Gas Specific Gravity
500	180	6696.5	0.7728
30	150	208.2	1.205
15	80	68.07	2.078

The Peng-Robinson EOS was used to generate the full range of PVT properties needed for input into the simulator. It is necessary to reduce the number of components to reduce the computer storage requirements and the time of the simulation. The procedure proposed by Whitson was used to reduce the components. The components were separated into seven groups, six pseudocomponents and one non-hydrocarbon, CO2. The pseudocomponents were defined as two pseudo-gases, GRP1 and GRP2, one gasoline group, GRP3 and three heavy pseudocomponents, GRP4, GRP5 and GRP6, and CO2 in the same way that Jaramillo[22] proposed when he characterized this fluid. Table 4.9 shows the final molar composition for the pseudocomponents.

Table 4.9 Pseudocomponent grouping and composition

Pseudocomponent	Components	Molar Percentage
	CO2	4.570
GRP1	N2-C1	69.490
GRP2	C2-C3	13.070
GRP3	C4-C6	4.690
GRP4	C7-C10	4.000
GRP5	C11-C16	2.500
GRP6	$C17\text{-}C30^+$	1.680

Finally, Table 4.10 shows the parameters used in the equation of state. The Binary Interaction Coefficients that were used in order to validate the simulation with the result presented by Whitson is explained in Table 4.11. The "a"centric factors and parachors are illustrated in Table 4.12

Table 4.10 Pseudocomponent properties

Components	Molecular	Pc, psig	Tc, °F	Zc	Vc, ft^3/lb-mol	s-Shifts
CO2	44.01	1056.6	88.79	0.27407	1.50573	-0.045792
GRP1	16.132	651.77	-117.46	0.28471	1.56885	-0.144168
GRP2	34.556	664.04	127.15	0.28422	2.63712	-0.095027
GRP3	67.964	490.47	350.279	0.27197	4.67964	-0.041006
GRP4	112.52	384.19	591.912	0.25668	7.26188	0.003672
GRP5	178.79	269.52	781.912	0.23667	11.09534	0.00893404
GRP6	303.64	180.2	1001.13	0.21972	17.67366	0.0115616

Table 4.11 Binary interaction coefficients

CO2	GRP1	GRP2	GRP3	GRP4	GRP5	GRP6
0.0657	0					
0.0657	0	0				
0.0657	0.0657	0.000	0			
0.0657	0.0248	0.0066	0	0		
0.0657	0.1052	0.0226	0	0	0	
0.0657	0.1231	0.0226	0	0	0	0

Table 4.12 A centric Factors and Parachors

Components	OMEGAA	OMEGAB	A centric Factors	Parachors
CO2	0.477635	0.070049	0.327911086	78
GRP1	0.477635	0.070049	0.01320204346	76.73060872
GRP2	0.477635	0.070049	0.1158061209	121.5282336
GRP3	0.457236	0.077796	0.2285995736	215.8816613
GRP4	0.457236	0.077796	0.3309925	358.2117489
GRP5	0.380486	0.07256	0.490667998	490.0019888
GRP6	0.380486	0.07256	1.124565237	781.5087913

4.4 Relative Permeability Curves

There is no definitive relative permeability model to represent fluid flow in gas condensate reservoirs due to the complexity of the laboratory measurements required and the dependency on interfacial tension, capillary forces, flow rate and other parameters. As a result, the relative permeability and saturation data for oil and gas were taken from the third SPE comparative case[34]. Table 4.13 presents the relative permeability and saturation data for oil and gas. Figure 4.6 demonstrates Cusiana gas condensate phase envelope. Relative permeability for oil and gas are shown in Figure 4.7

Table 4.13 Relative permeability and saturation data for oil and gas*

Gas and oil saturation functions			
Sg	Krg	So	Kro
0.84	0.74	0	0
0.8	0.69	0.04	0
0.76	0.62	0.08	0
0.72	0.562	0.12	0
0.68	0.505	0.16	0
0.64	0.45	0.2	0
0.6	0.4	0.24	0
0.56	0.349	0.28	0.005
0.48	0.26	0.32	0.012
0.44	0.222	0.36	0.024
0.4	0.187	0.4	0.04
0.36	0.156	0.44	0.06
0.32	0.126	0.48	0.082
0.28	0.1	0.52	0.112
0.24	0.078	0.56	0.15
0.2	0.058	0.6	0.196
0.16	0.04	0.68	0.315
0.12	0.026	0.72	0.4
0.08	0.013	0.76	0.513
0.04	0.005	0.8	0.65
0	0	0.84	0.8

* From SPE comparative case[34]

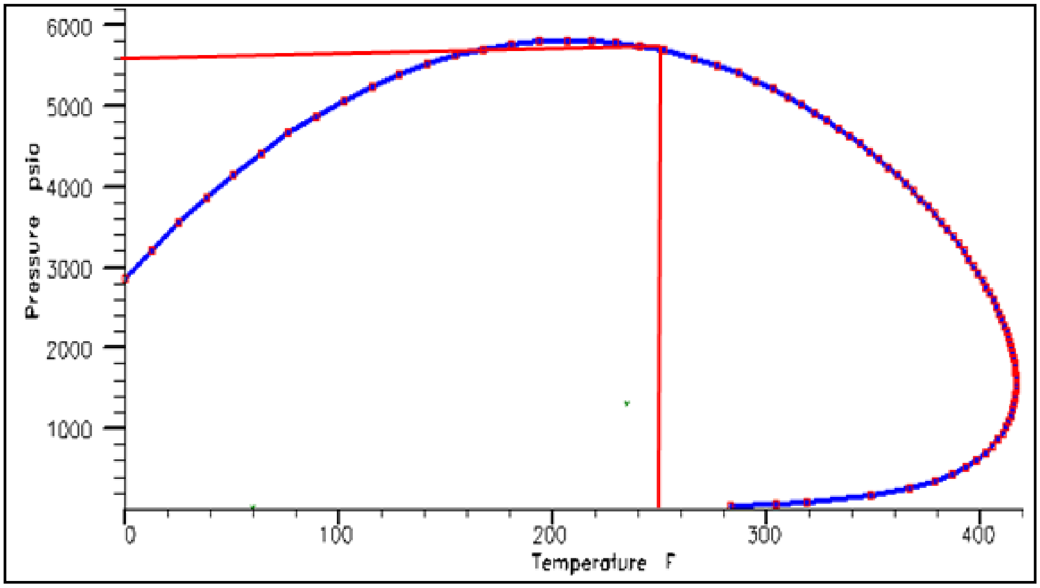

Figure 4.6 Cusiana gas condensate phase envelope

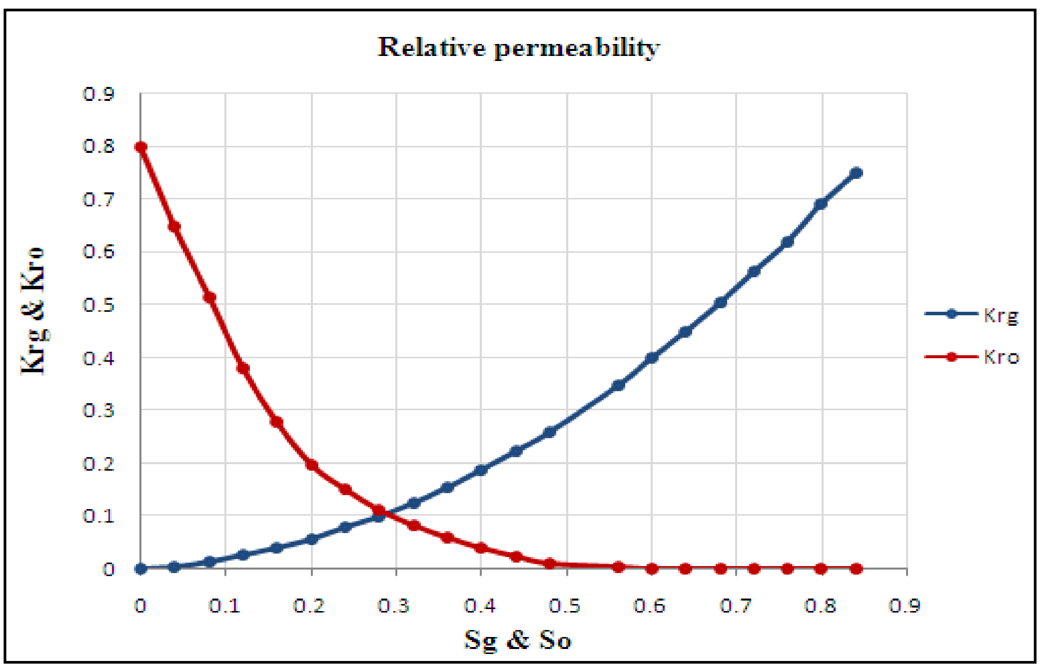

Figure 4.7 Relative permeability for gas and oil

CHAPTER 5

RESULTS AND DISCUSSION

In this research study, a total of 180 simulation runs were made in order to investigate the effects of well and reservoir parameters on the performance of horizontal and vertical wells in retrograde gas-condensate reservoirs for all reservoir cases described in Chapter 4. Several performance plots in terms of oil and gas recovery factors as a function of time were made using the results generated in this study. These plots are useful for evaluating the performance of the horizontal and vertical wells in retrograde gas-condensate reservoirs. In this research, the abandonment condition for both horizontal and vertical wells is reached when the well's production rate becomes less than 100 MSCF/D for a bottom-hole flowing pressure of 700 psia.

In this chapter, reservoir simulation results are presented and detail analysis of results will be made in order to investigate the effects of several well and reservoir parameters on the performance of horizontal and vertical wells in retrograde gas-condensate reservoirs. Parameters investigated include the length of the horizontal section of the well, reservoir thickness, drainage area size and shape, formation permeability, and vertical to horizontal permeability ratio (k_v/k_h).

Table A.1 through A.15 show comparison of average reservoir pressure, bottom-hole pressure and gas and oil recovery factors for vertical and horizontal wells for various reservoir parameters. Recovery factors for free gas, gross gas, and oil versus time will be presented in graphical form, analyzed and compared. For example, Figures 5.1 through 5.3 show the plots for free gas recovery factor ("FGRF"), gross gas recovery factor ("GGRF"), and oil recovery factor ("ORF"), respectively, as a function of time for 160-acre and 80-acres square drainage area. The plots corresponding to the letter "V" show vertical well performance and the plots corresponding to the letter "H" show horizontal well performance. These three plots show that for high value of horizontal well penetration ratio, the free-gas and gross-gas reserves will be produced 3 times faster by the horizontal well compared to vertical well in a thin, low-permeability reservoir. For these cases, the ultimate recovery factors for the gross gas and for the free gas are about 10% higher for the horizontal well compared with the vertical well. However, for these cases, the ultimate recovery factor for oil is about 2 to 3 percent lower for horizontal well compared to vertical well. Interestingly, for the wells located in 80-acre square drainage area, the oil reserves are produced at about the same time for both horizontal and vertical wells and it will take the vertical wells three times longer to increase the oil recovery factor by an additional 3% at abandonment conditions. However, for the wells located in 160-acre square drainage area, the oil recovery factor for the vertical well is about 3% lower than that obtained by horizontal well at the abandonment condidtions of the horizontal well; it will then take the vertical well three times longer to achieve an ultimate oil recovery factor. Therefore, considering the above results and discussion, for the reservoir and well parameters shown in these three figures, the reservoir should be developed with horizontal wells.

Figures 5.4 through 5.12 show the comparison of oil and gas recovery factors for vertical and horizontal wells for various reservoir parameters. Similar analysis can be conducted on these figures as was conducted above on Figures 5.1 through 5.3. As observed from Figures 5.4 through 5.12, there is no difference in ultimate oil and gas recovery factors for horizontal and vertical wells. However, there is a significant difference in the time to reach the abandonment conditions. In these case, the horizontal well reaches the abandonment conditions much faster than the vertical well; in other words, the ultimate reserves are produced much faster by the horizontal well.Tables A.1 through A.6 show comparision of average reservoir pressure, bottom-hole pressure and gas and oil recovery factors for vertical and horizontal wells for various reservoir parameters. As can also be observed from these tables, the ultimate oil and gas recovery factors are almost the same for both well types; the only difference is in the time to reach the ultimate recovery (i.e., to reach abandonment conditions). For example, Tables A.1 and A.2 show that the horizontal well will produce the ultimate reserves in 3.59 years while the vertical well will produce the ultimate reserves in 4.38 years. Tables A.3 and A.4 show the time to reach abandonment conditions are 10.54 years for the vertical well and 4.32 years for the horizontal well.

Figures 5.4 through 5.8 show that, for a formation thickness of 25 feet and vertical to horizontal permeability ratio of 1, as the horizontal permeability increases, the performance of a horizontal with a penetration ratio of 0.8 becomes almost identical with the performance of a vertical well in terms of both the ultimate recovery factors and the time to reach abandonment conditions. At lower pemeabilities, horizontal well produces the ultimate reserves much faster. Therefore, for such high-permeability reservoirs, the reservoir may be developed with vertical wells instead of long horizontal wells, even in the case of low formation thickness of 25 feet. The performance of long horizontal wells and vertical wells become almost identical in high-permeability, thick reservoirs, as shown in Figures 5.9 through 5.12. Therefore, these reservoirs may be developed with vertical wells.

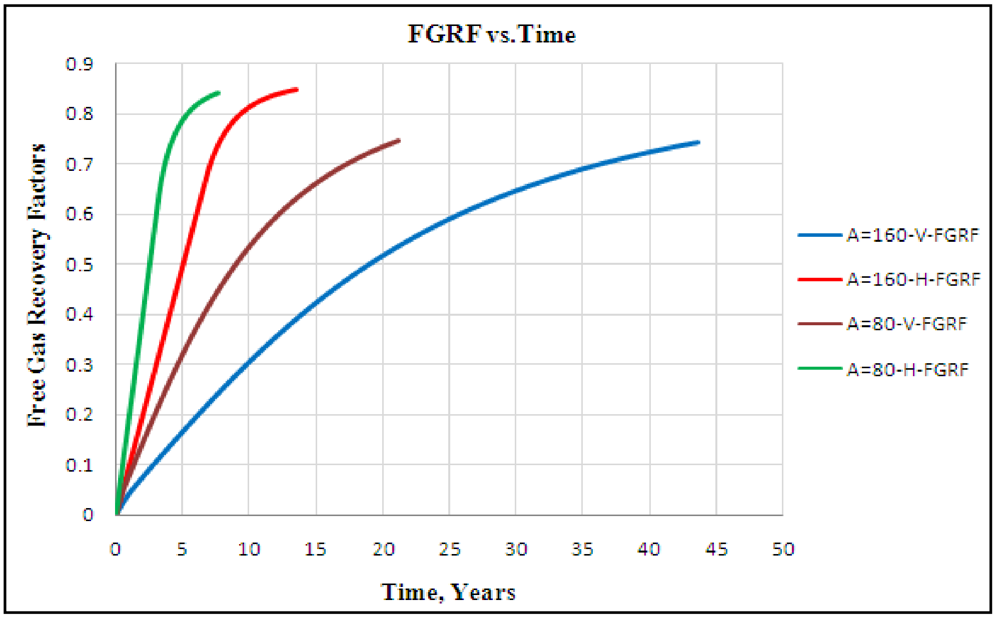

Figure 5.1 Free gas recovery factors for vertical and horizontal wells at A=160 and 80 acres, square drainage area, k_h=1md, h=25ft, L_H=2112ft and k_v/k_h=1

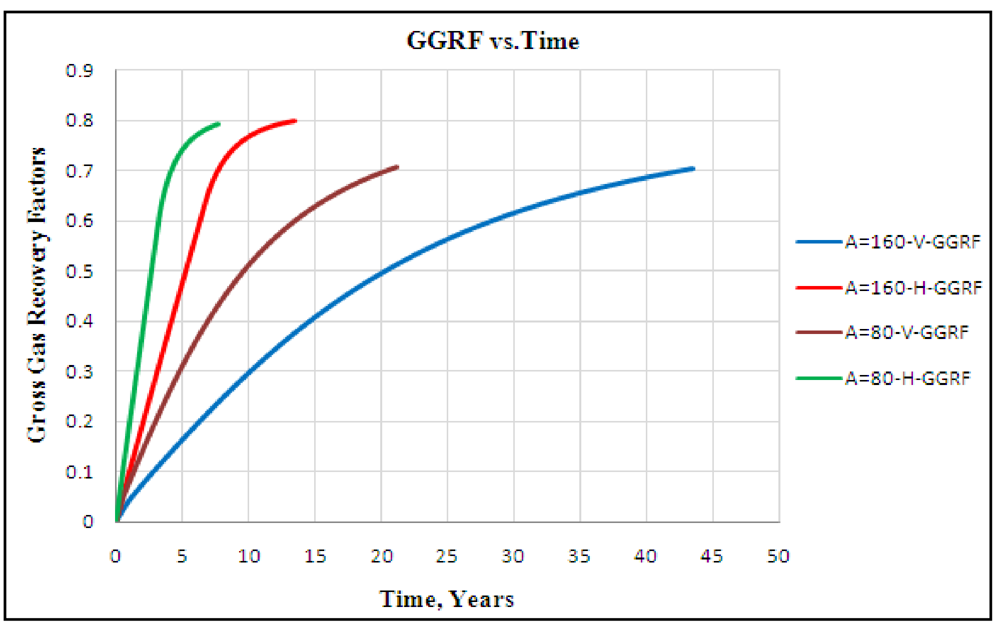

Figure 5.2 Gross gas recovery factors for vertical and horizontal wells at A=160 and 80 acres, square drainage area, k_h=1md, h=25ft, L_H=2112ft and k_v/k_h=1

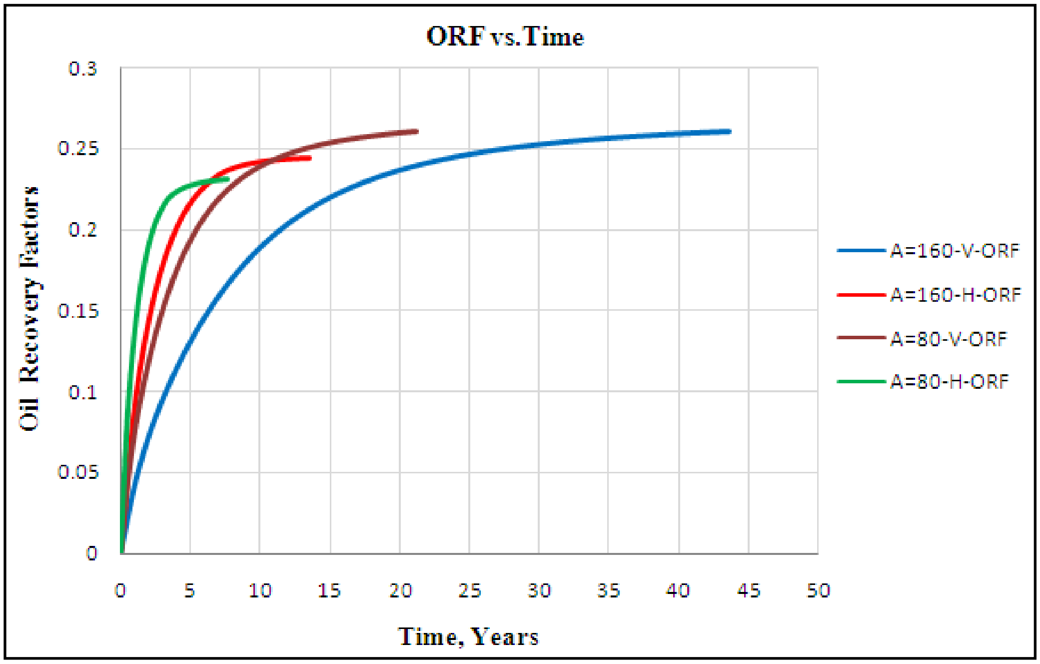

Figure 5.3 Oil recovery factors for vertical and horizontal wells at A=160 and 80 acres, square drainage area, k_h=1md, h=25ft, L_H=2112ft and k_v/k_h=1

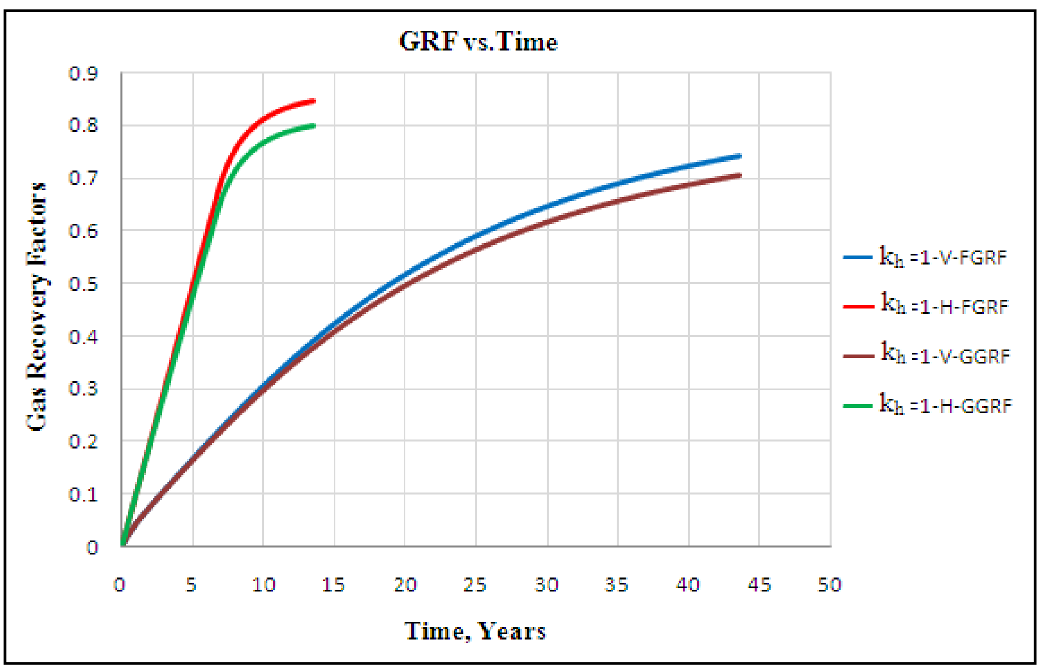

Figure 5.4 Free and gross gas recovery factors for horizontal and vertical wells at A= 160 acres, square drainage area, h=25ft, L_H=2112ft, k_h=1md and k_v/k_h=1

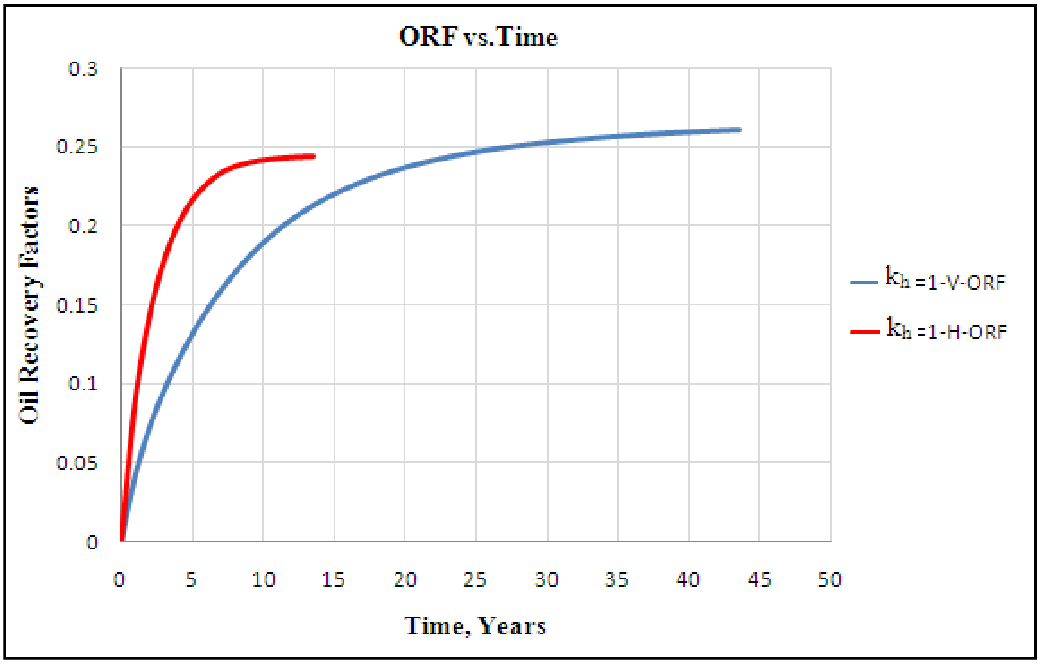

Figure 5.5 Oil recovery factors for horizontal and vertical wells at A=160 acres, square drainage area, h=25ft, L_H=2112ft, k_h=1md and k_v/k_h=1

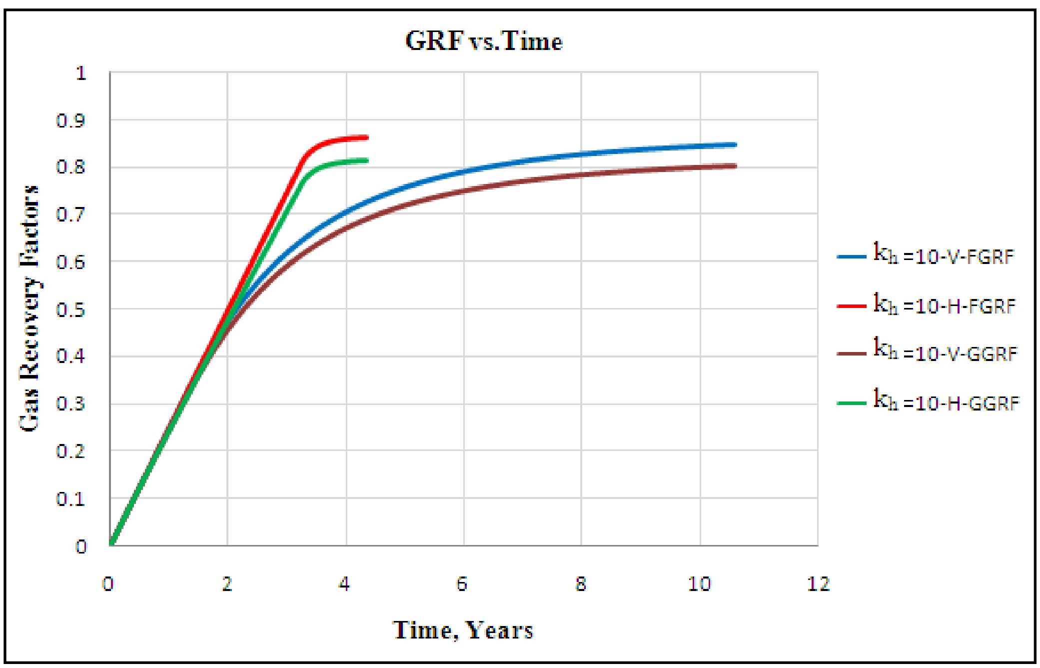

Figure 5.6 Free and gross gas recovery factors for horizontal and vertical wells at A= 160 acres, square drainage area, h=25ft, L_H=2112ft, k_h=10md and k_v/k_h=1

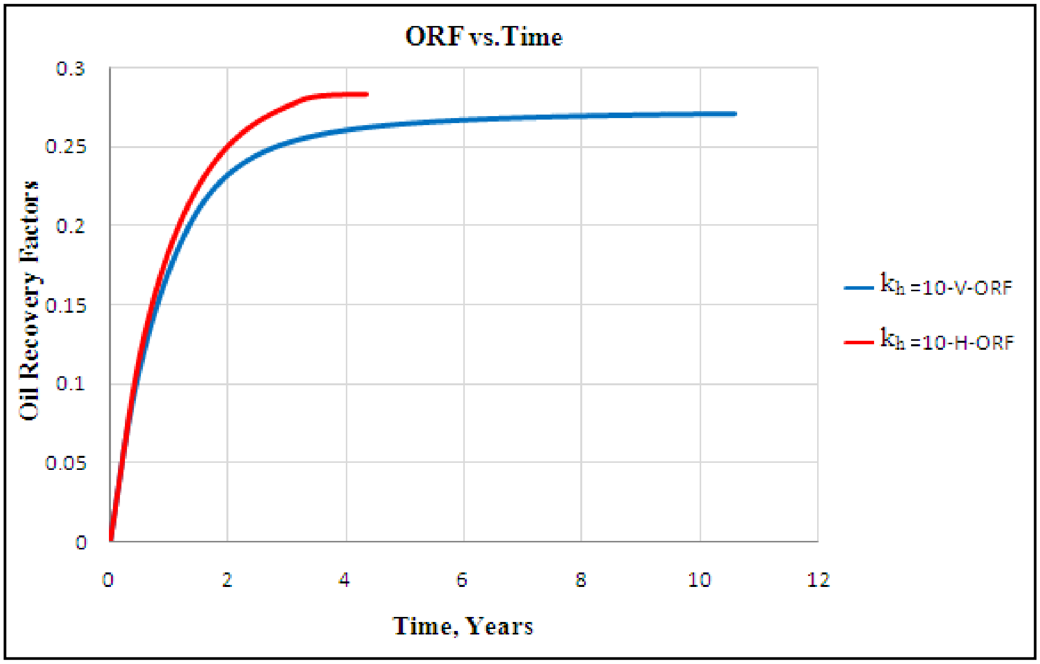

Figure 5.7 Oil recovery factors for horizontal and vertical wells at A=160 acres, square drainage area, h=25ft, L_H=2112ft, k_h=10md and k_v/k_h=1

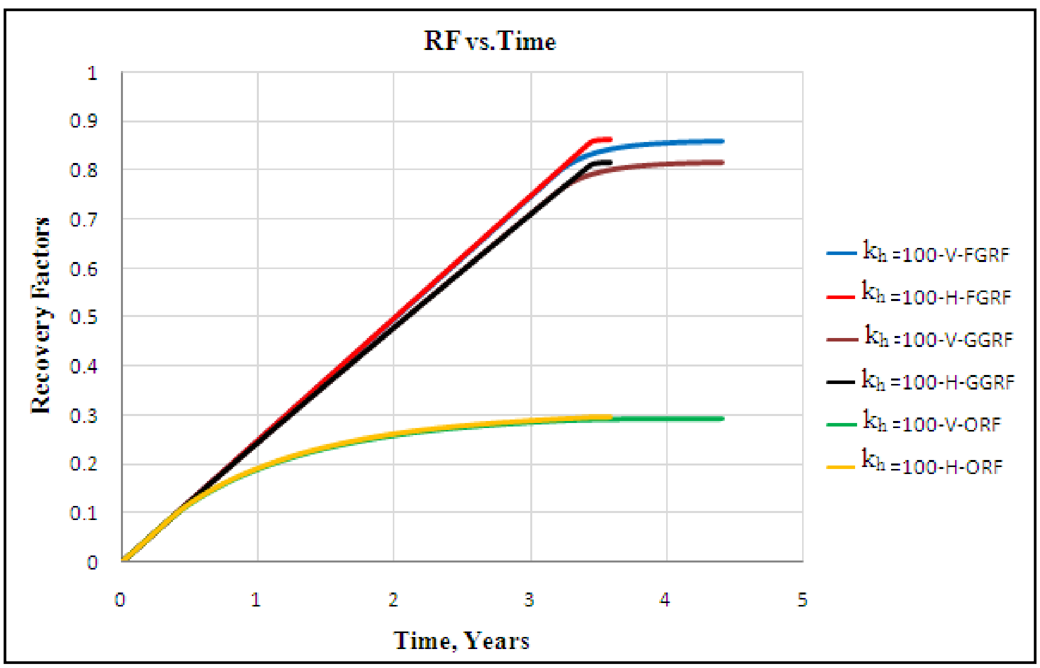

Figure 5.8 Gas and oil recovery factors for horizontal and vertical wells at A=160 acres, square drainage area, h=25ft, L_H=2112ft, k_h=100md and k_v/k_h=1

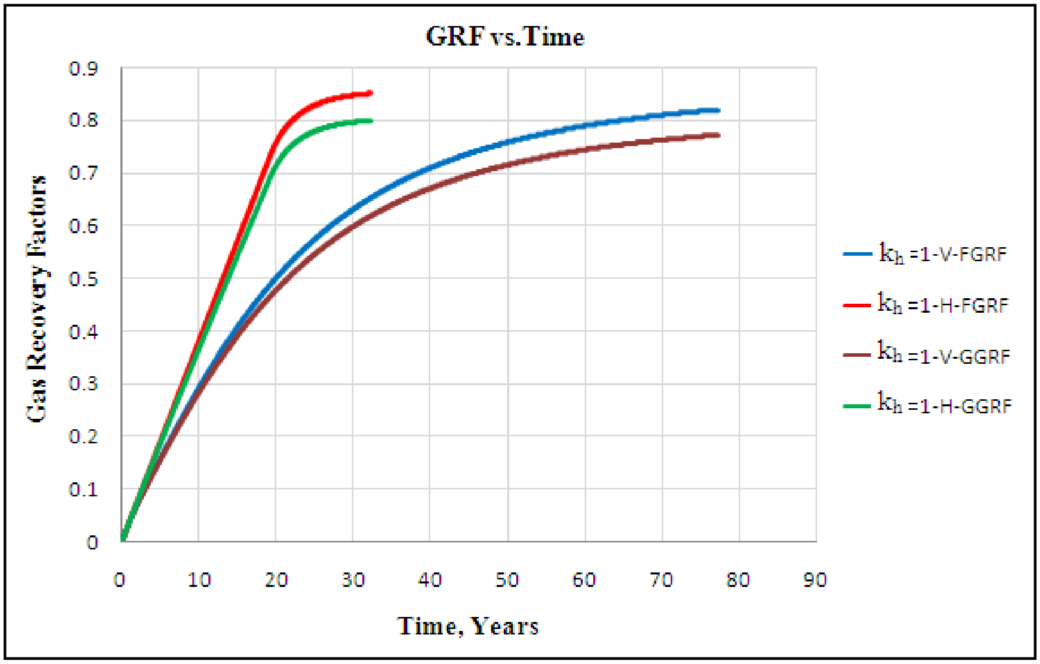

Figure 5.9 Free and gross gas recovery factors for horizontal and vertical wells at A= 160 acres, square drainage area, h=100ft, L_H=2112ft, k_h=1md and k_v/k_h=1

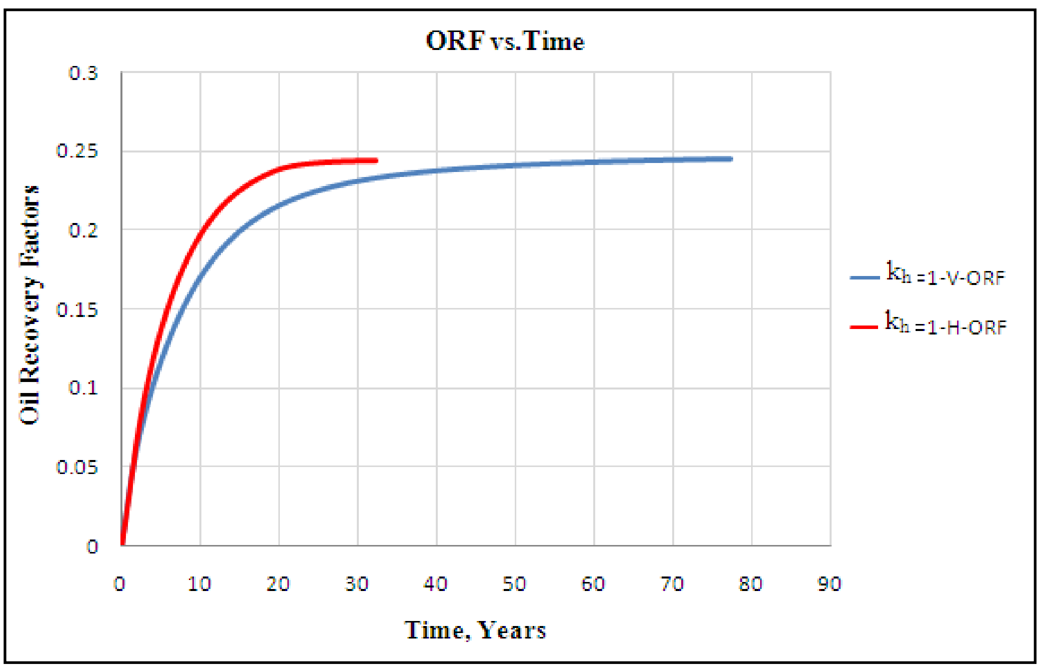

Figure 5.10 Oil recovery factors for horizontal and vertical wells at A=160 acres, square drainage area, h=100ft, L_H=2112ft, k_h=1md and kv/kh=1

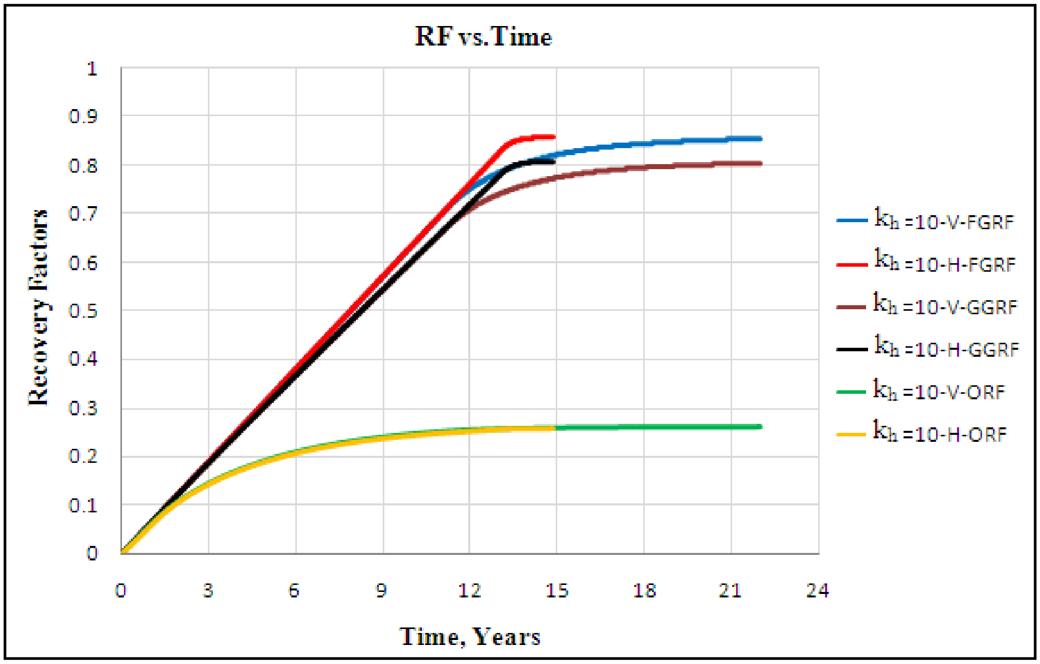

Figure 5.11 Gas and oil recovery factors for horizontal and vertical wells at A=160 acres, square drainage area, h=100ft, L_H=2112ft, k_h=10md and k_v/k_h=1

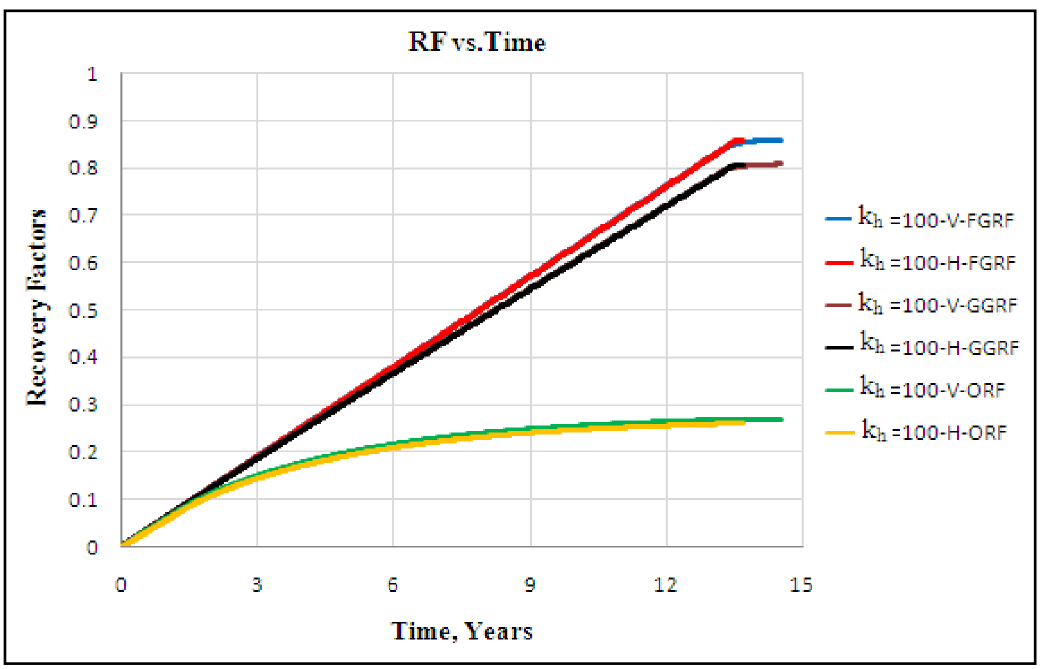

Figure 5.12 Gas and oil recovery factors for horizontal and vertical wells at A=160 acres, square drainage area, h=100ft, L_H=2112ft, k_h=100md and k_v/k_h=1

5.1 The Effect of Horizontal Permeability

As shown in Figures 5.13 through 5.18, results for three values of horizontal permeability (1, 10 and 100 md) were generated and analyzed in order to investigate the effect of horizontal permeability on the performance of horizontal and vertical wells. In these cases, the only variation is horizontal permeability. All cases had the same reservoir geometries and rock and fluid properties. Figures 5.13 through 5.15 show the effect of horizontal permeability on the recovery factors for free-gas, gross-gas, and oil for horizontal wells and vertical wells located in 160-acres square drainage area, reservoir pay thickness of 25 ft, k_v/k_h=1, and horizontal well length of 2112 feet, while Figures 5.16 through 5.18 illustrate the effect of horizontal permeability on the recovery factors for the same reservoir and well parameters, except that formation thickness is 100 feet. For clarity, Figures 5.19 through 5.21 show the effect of horizontal permeability on the recovery factors for a vertical well located in a 160-acre square drainage area for a reservoir thickness of 25 feet and k_v/k_h =1.

As can be concluded from Figures 5.13 through 5.18, the performance of horizontal and vertical wells can be considered identical when horizontal permeability is high (10 md. and 100 md.) and horizontal to vertical permeability is equal to 1, regardless of the value of formation thickness. However, at horizontal permeability of 1 md, the performance of horizontal wells is much better than vertical wells, regardless of formation thickness. The advantages of a horizontal well over a vertical well in a reservoir with horizontal permeability of 1 md increases as formation thickness decreases, as can be concluded from these figures. In cases where horizontal permeability is 1 md, the horizontal well produces the reserves about 3.2 times faster than the vertical well when formation thickness is 25 feet while it produces the reserves about 2.5 times faster when formation thickness is 100 feet. In addition, in the cases of horizontal permeability of 1 md, the gross-gas and free-gas recovery factors for horizontal well is about 10% higher than those of vertical wells when formation thickness is 25 feet while these recovery factors for horizontal and vertical wells are identical when formation thickness is 100 feet; although, as mentioned above, horizontal well produces the reserves much faster. It is important to note that all of the above statements are valid for horizontal well penetration ratio of 0.8.

Therefore, reservoirs with horizontal permeability greater than 10 md and horizontal to vertical permeability ratio of 1 may be developed with vertical wells, regardless of formation thickness. Reservoirs with horizontal permeability in the order of magnitude of 1 md and vertical to horizontal permeability ratio of 1 should be developed with horizontal wells, regardless of formation thickness. Figures 5.19 through 5.21 show that vertical well performance becomes very poor as formation permeability decreases from 10 md to 1 md.

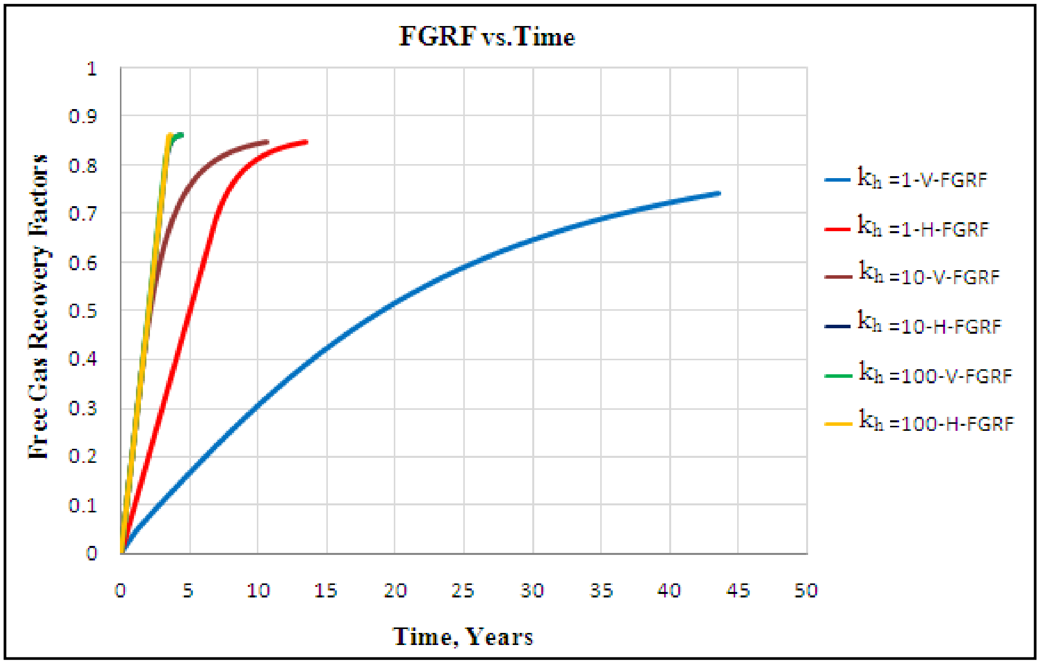

Figure 5.13 Effect of k_h on free gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, h=25ft, L_H=2112ft and k_v/k_h=1

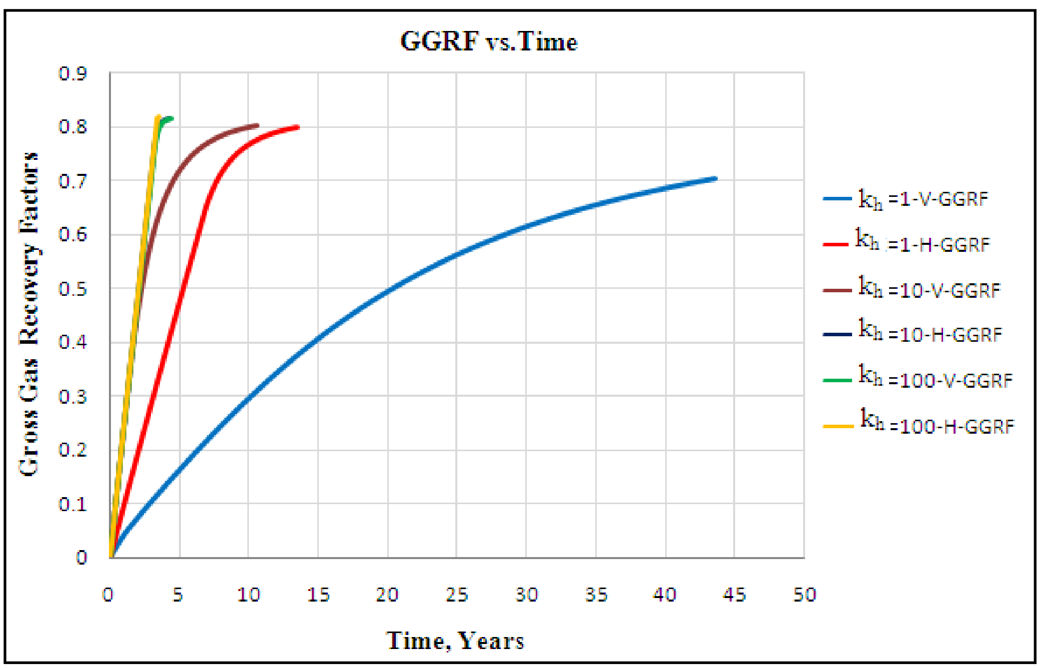

Figure 5.14 Effect of k_h on gross gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, h=25ft, L_H =2112ft and k_v/k_h=1

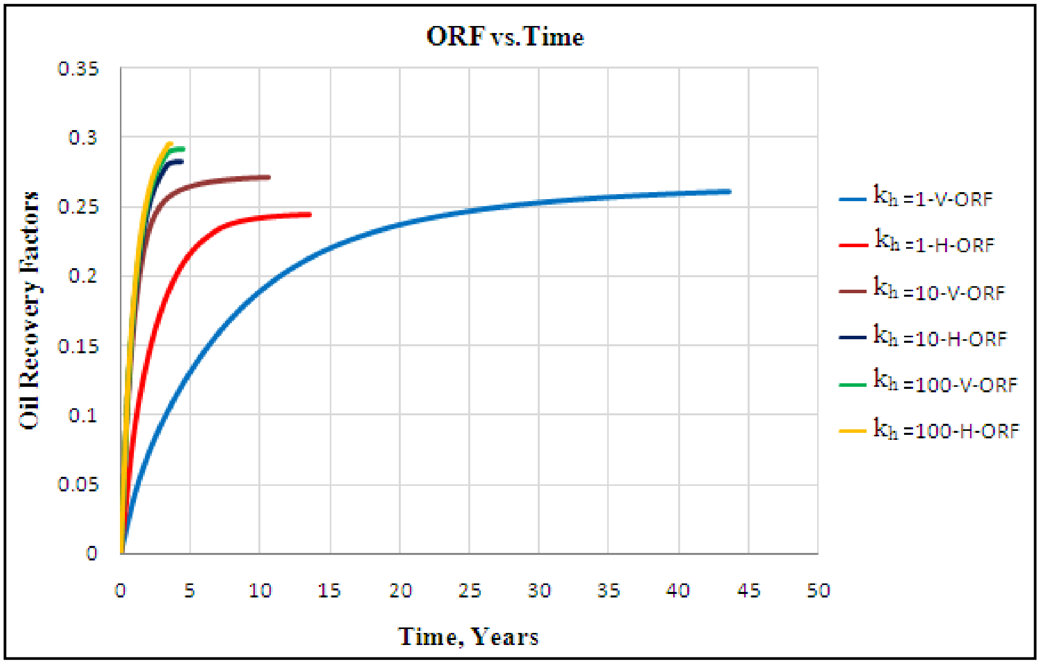

Figure 5.15 Effect of k_h on oil recovery factors for vertical and horizontal wells at A= 160 acres, square drainage area, h=25ft, L_H=2112ft and k_v/k_h=1

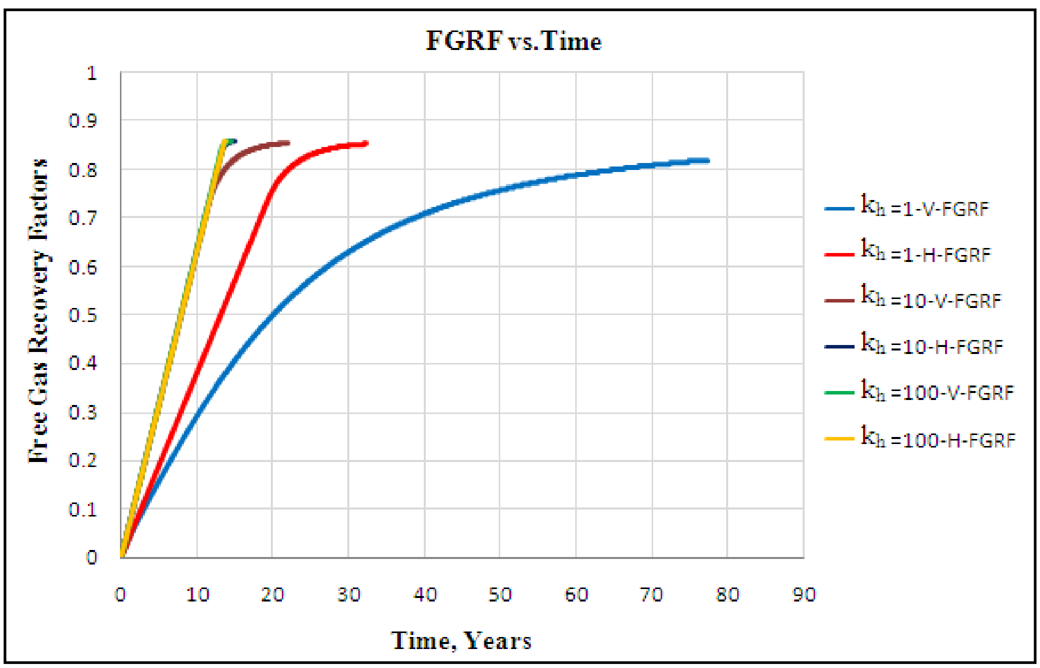

Figure 5.16 Effect of k_h on free gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, h=100ft, L_H=2112ft and k_v/k_h=1

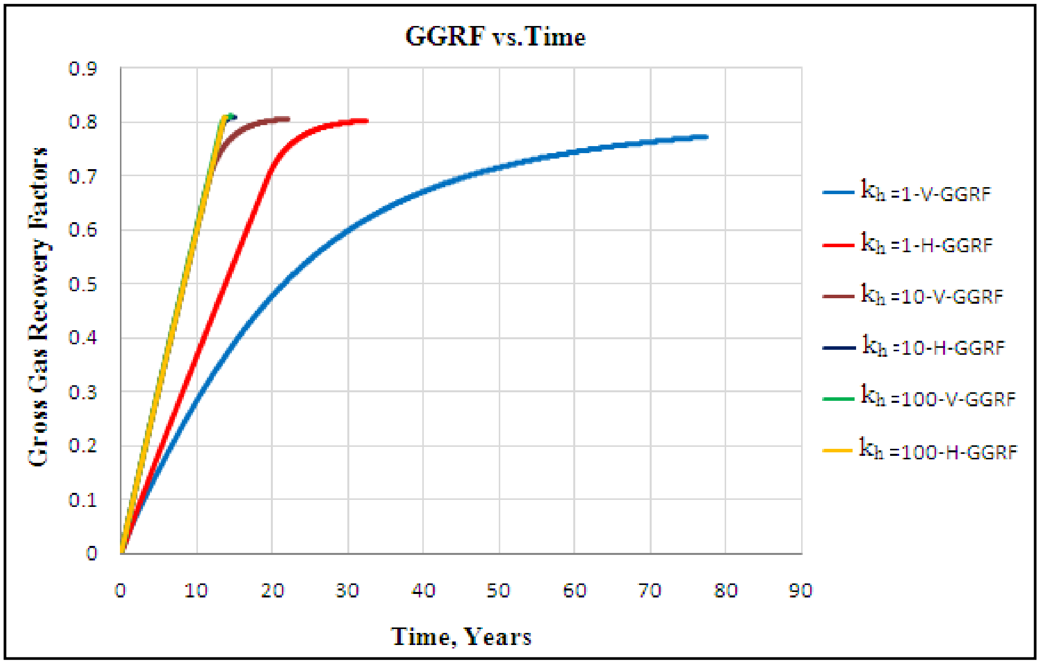

Figure 5.17 Effect of k_h on gross gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, h=100ft, L_H=2112ft and k_v/k_h=1

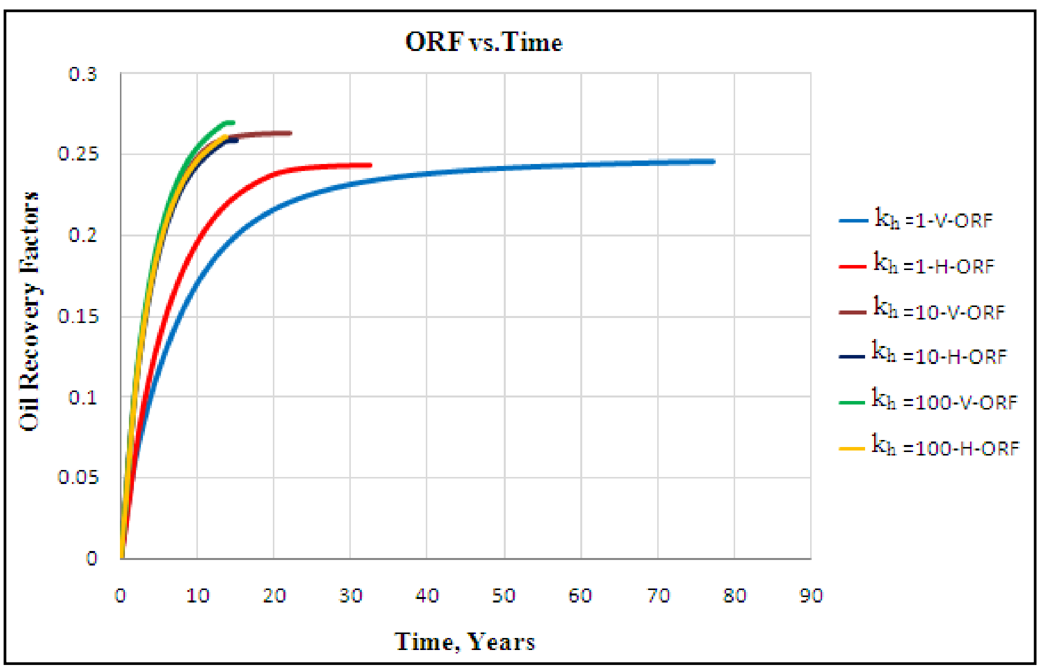

Figure 5.18 Effect of k_h on oil recovery factors for vertical and horizontal wells at A= 160 acres, square drainage area, h=100ft, L_H=2112ft and k_v/k_h=1

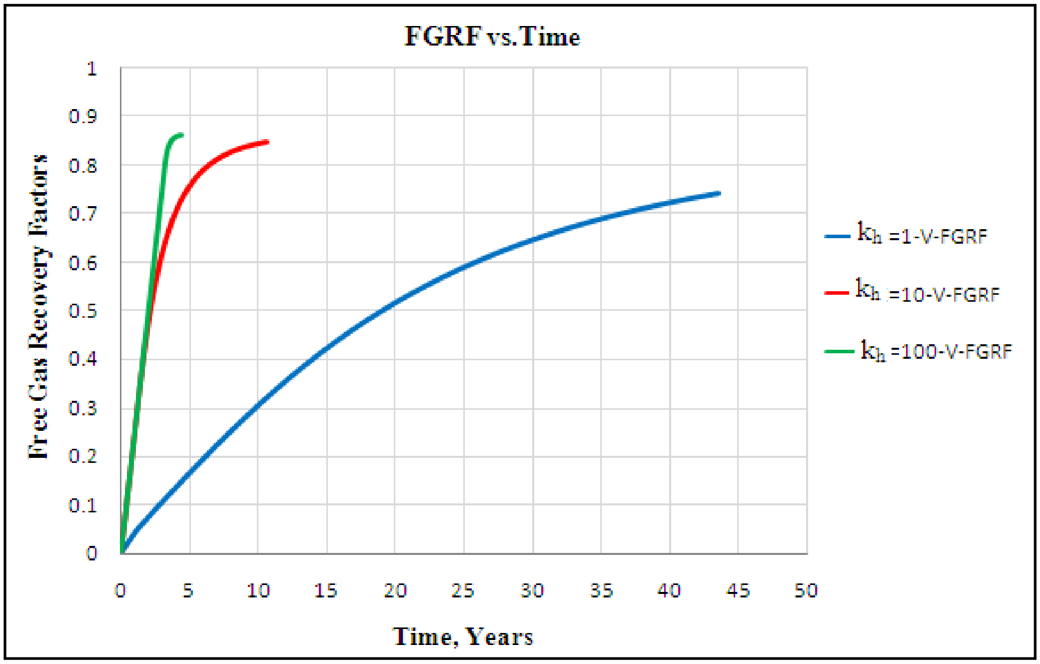

Figure 5.19 Effect of k_h on free gas recovery factors for vertical well at A=160 acres, square drainage area and h=25ft

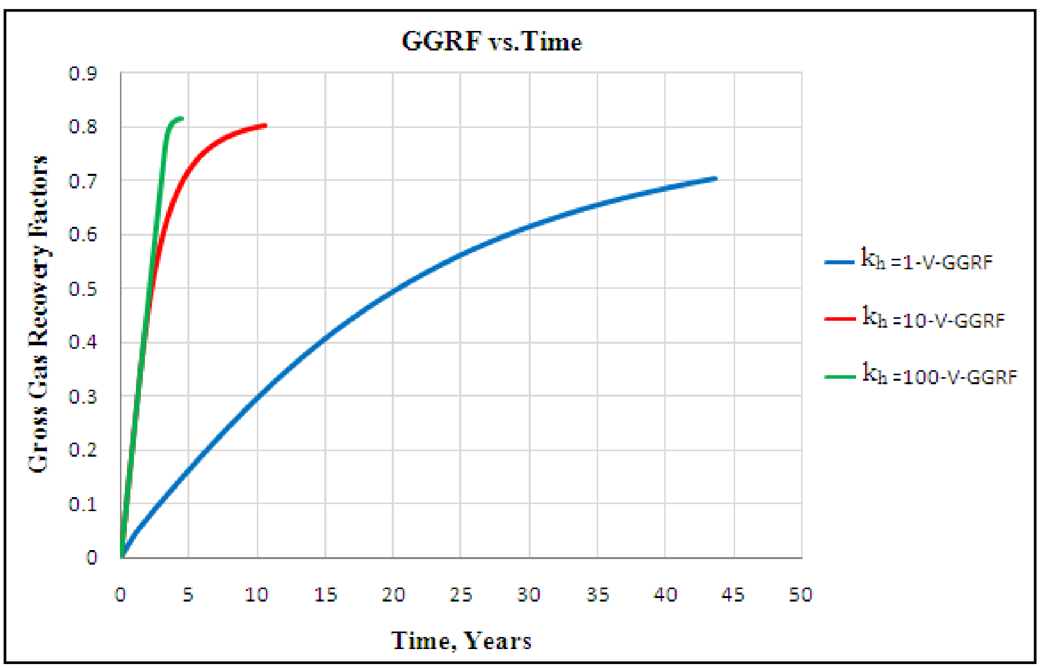

Figure 5.20 Effect of k_h on gross gas recovery factors for vertical well at A=160 acres, square drainage area and h=25ft

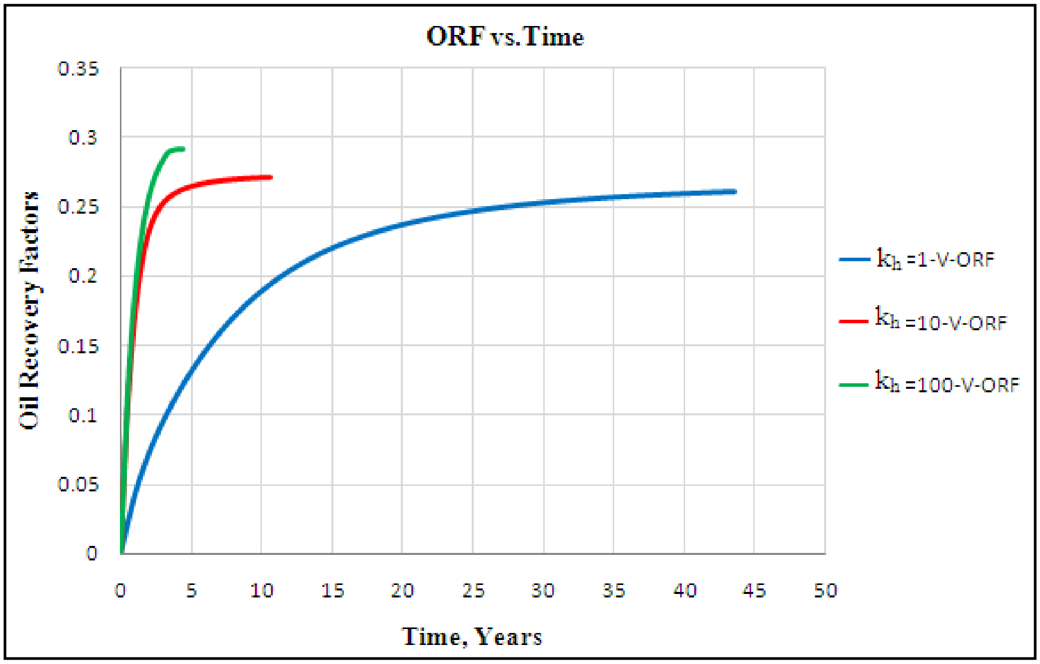

Figure 5.21 Effect of k_h on oil recovery factors for vertical well at A=160 acres, square drainage area and h=25ft

5.2 The Effect of Horizontal Well Penetration Ratio

Numerous simulation runs were made in order to investigate the effect of length of the horizontal section of the well on the recovery factors of free-gas, gross-gas, and oil for horizontal wells. In these simulation runs, reservoir geometries and rock and fluid properties were fixed and the only variation is the length of the horizontal section of the horizontal well. Three wellbore lengths of 528 ft, 1056 ft and 2112 ft for the case of 160-acres square drainage area and 374 ft, 748 ft and 1496 ft for the case of 80-acres square drainage area were investigated corresponding to horizontal well penetration ratios ($L_H/2Xe$) of 0.2, 0.4, and 0.8 for each drainage area size. Figures 5.22 through 5.31 show the effect of horizontal well penetration ratio on recovery factors of free-gas and oil for the horizontal well. These figures also show comparison with vertical well. Figures 5.22 through 5.26 are for the case of 160-acres square drainage area, reservoir thickness of 25 ft, horizontal permeabilities of 1, 10 and 100 md respectively, and $k_v/k_h=1$, while Figures 5.27 through 5.31 are for the same reservoir parameters, except that the formation thickness is 100 feet in these cases.

As can be concluded from the results shown in Figures 5.22 and 5.23, in a thin (i.e., 25 feet), low horizontal permeability (i.e., 1 md) retrograde gas-condensate reservoir with vertical to horizontal permeability ratio of 1, a horizontal well with penetration ratio of 0.8 performs much better than a horizontal well with penetration ratios of 0.2 and 0.4. The oil recovery factor for a horizontal well with penetration ratios of 0.2 and 0.4 is considerably less than the recovery factor of a vertical well and than that of a horizontal well with penetration ratio of 0.8. In these cases, the recovery factors of gross-gas and free-gas for the horizontal well are higher than those of vertical well, regardless of the horizontal well penetration ratio. In such reservoirs, the free-gas and gross-gas reserves are produced much faster by the horizontal well as compared to vertical well, regardless of the horizontal well penetration ratio. However, in such reservoirs, at the time that the horizontal wells with penetration ratios of 0.2 and 0.4 reach their maximum oil recovery factor, a vertical well has produced at considerably higher oil recovery factor. In such reservoirs, only a horizontal well with penetration ratio of 0.8 performs better than the vertical well in regards to oil recovery at a time when abandonment condition of the horizontal well is reached.

In a thin formation with vertical to horizontal permeability ratio of 1, as horizontal permeability increases, the effect of increase in horizontal well penetration ratio on well performance decreases, as shown in Figures 5.24 through 5.26; for example, at a horizontal permeability of 100 md, the performance of the horizontal well and the vertical well will become identical with respect to the oil and gas recovery factors and almost identical with resepect to abandonment time, regardless of the horizontal well penetration ratio, as shown in Figure 5.26. This means that for thin formations (of about 25 feet) with high horizontal and vertical permeabilities (of about 100 md), a vertical well should be used to develop a retorgrade gas-condensate reservoir.

Results shown in Table A.22 indicate that in a thin formation with vertical to horizontal permeability ratio of 0.1, vertical well will perform slightly better than horizontal well in regards to oil and gas recovery factors, regardless of the horizontal well penetration ratio. In this case, only the horizontal well with penetration ratio of 0.8 reaches the abandonment conditions at negligibly earlier time than the vertical well (4.1 years for horizontal well penetration ratio of 0.8 as compared to 4.38 years for the vertical well). Therefore, such reservoirs should be developed with vertical wells.

As in the case of thin reservoirs described above, in thick formations with vertical to horizontal permeability ratio of 1, as horizontal permeability increases, the effect of increase in horizontal well penetration ratio on well performance also decreases but more pronounced than in the case of thin reservoirs. The cases for thick formation (100 feet) are shown in Figures 5.27 through 5.30. For example, as shown in Figures 5.27 and 5.28, at a horizontal permeability of 1 md, horizontal well performs much better than the vertical well in regards to gross-gas and free-gas recovery factors and time to reach the abandonment conditions, regardless of the horioznt al well penetration ratio; however, only the horizontal well with penetration ratio of 0.8 performs better than the vertical well in regards to oil recovery at the abandonment time of the horizontal well. At a horizontal permeability of 100 md, the performance of the horizontal well and the vertical well will become identical with respect to the oil and gas recovery factors and abandonment time, regardless of the horizontal well penetration ratio, as shown in Figure 5.30. At a horizontal permeability of 10 md, the performance of the horizontal and vertical well will become identical with respect to the oil and gas recovery factors, regardless of the horioznt al well penetration ratio; however, the horizontal well still has some advantage over the vertical well by reaching the abandonment conditions earlier (but not significantly earlier as was the case in thin formations with horizontal permeability of 10 md that was shown in Figure 5.24 and 5.25). Interestingly, in thick formations with high permeability, the performance of horizontal and vertical wells become identical when the vertical to horizontal permeability ratio is equal to 0.1, regardless of the horizontal well penetration ratio. These results, therefore, indicate that for thick formations (of about 100 feet) with high horizontal permeability (of about 20 md or higher), a vertical well should be used to develop a retorgrade gas-condensate reservoir, regardless of the vertical to horizontal well permeability ratio.

Results shown in Tables A.21 and A.22 indicate that reservoirs with low horizontal permeability of 1 md and low vertical to horizontal permeability of 0.1 should not be developed with horizontal wells with penetration ratio of 0.2, regardless of formation thickness. Such reservoirs should be developed with horizontal wells of penetration ratio of 0.4 or higher for formation thicknesses of 25 feet and 50 feet, regardless of the value of k_v/k_h, and with horizontal wells of penetration ratio of 0.4 and higher for formation thickness of 100 feet and k_v/k_h values of 0.5 and 1. In reservoirs with horizontal permeability of 1 md, horizontal wells of penetration ratio of 0.8 perform better than the vertical wells, for all values of formation thicknesses and k_v/k_h considered.

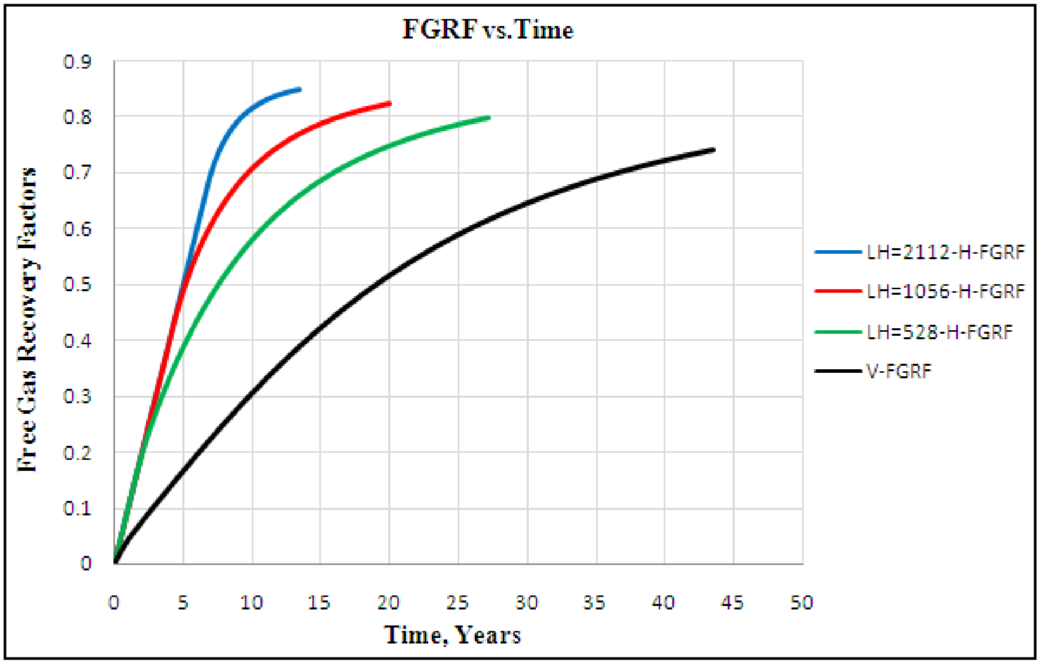

Figure 5.22 Effect of well lengths on free gas recovery factors for horizontal well at A= 160 acres, square drainage area, h=25ft, k_h=1md and k_v/k_h=1

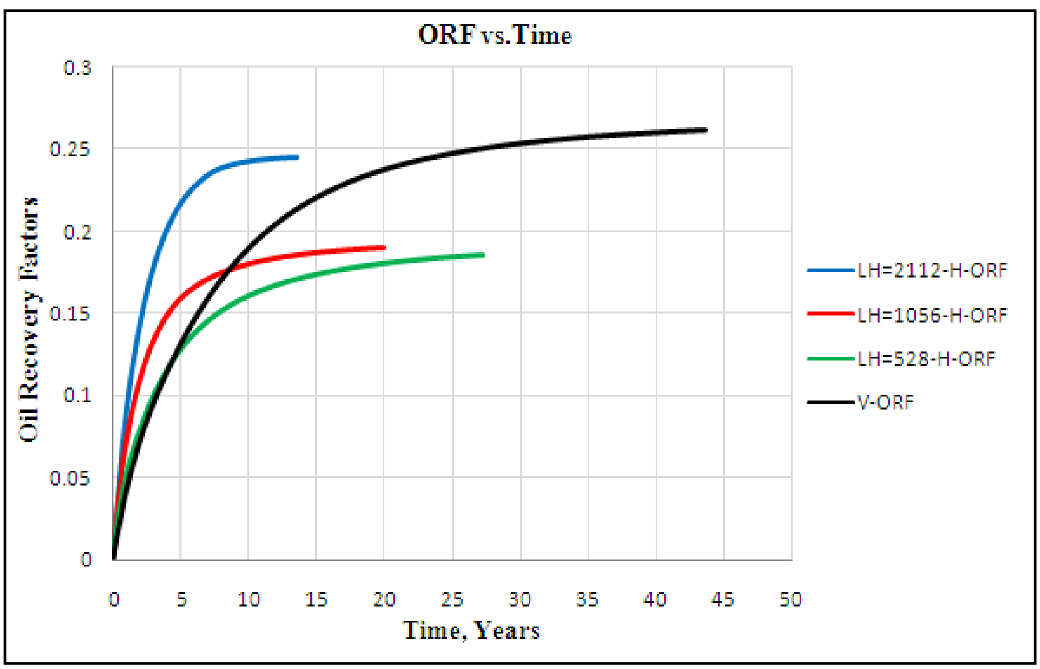

Figure 5.23 Effect of well lengths on oil recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1md and k_v/k_h=1

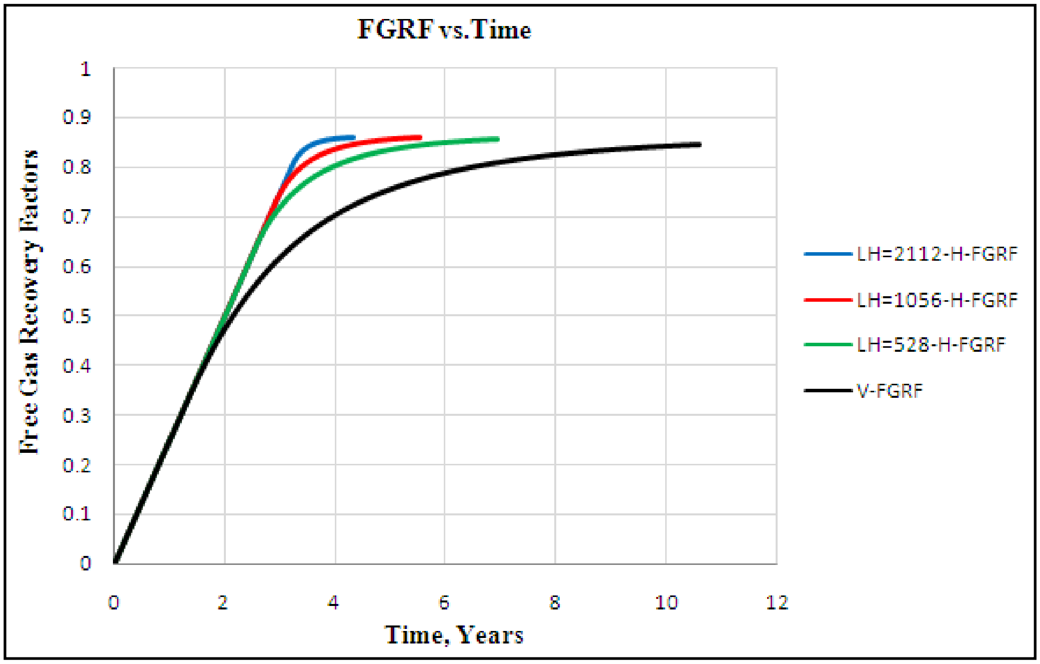

Figure 5.24 Effect of well lengths on free gas recovery factors for horizontal well at A= 160 acres, square drainage area, h=25ft, k_h=10 md and k_v/k_h=1

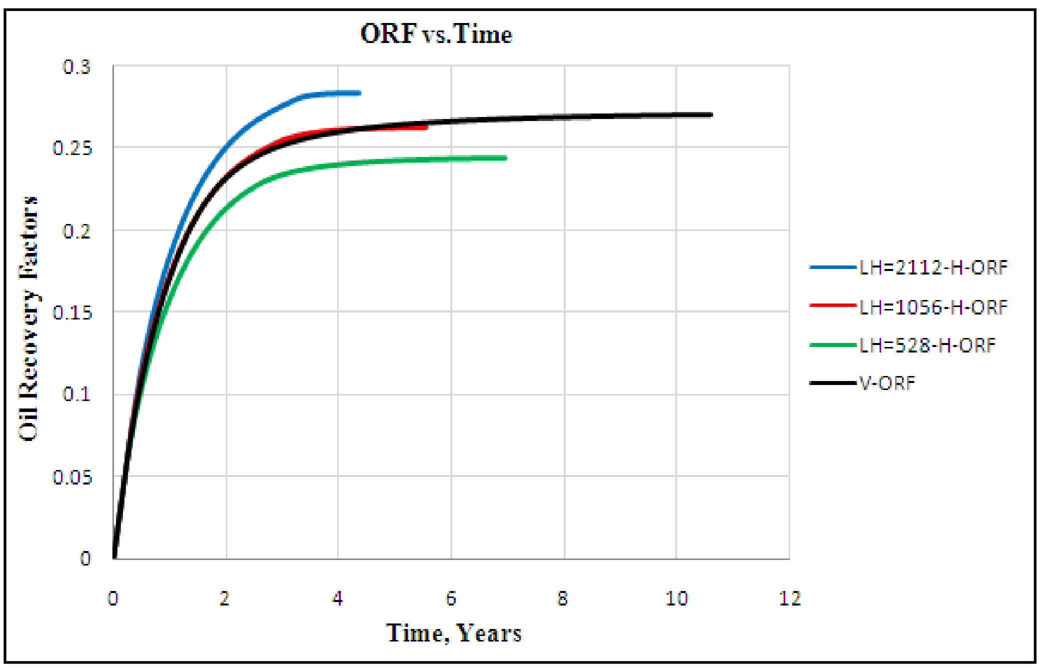

Figure 5.25 Effect of well lengths on oil recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md and k_v/k_h=1

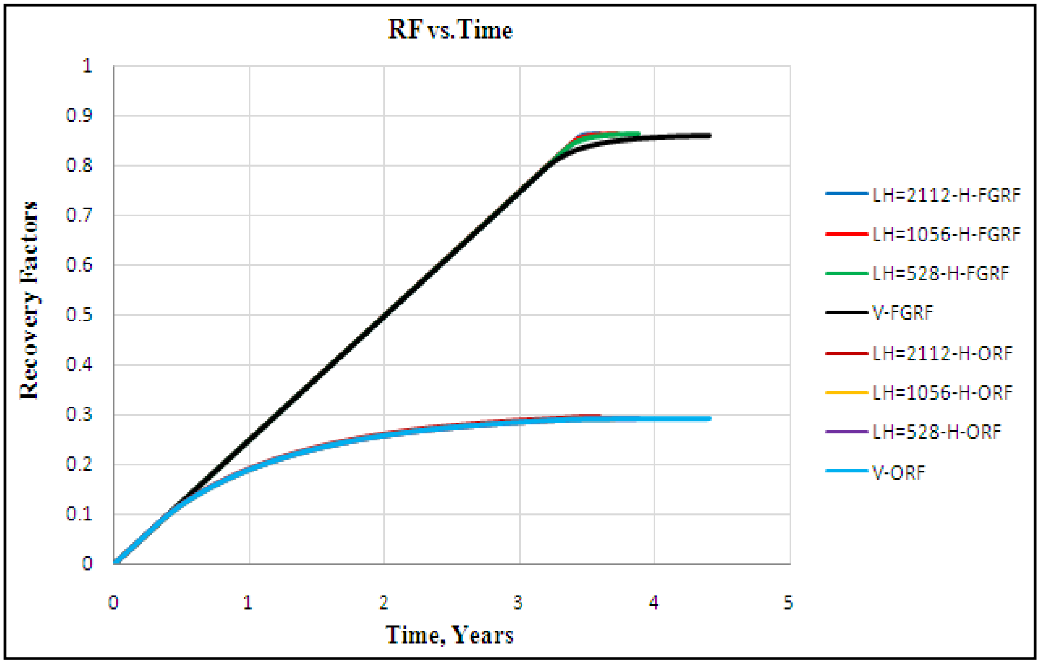

Figure 5.26 Effect of well lengths on free gas and oil recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=100 md and k_v/k_h=1

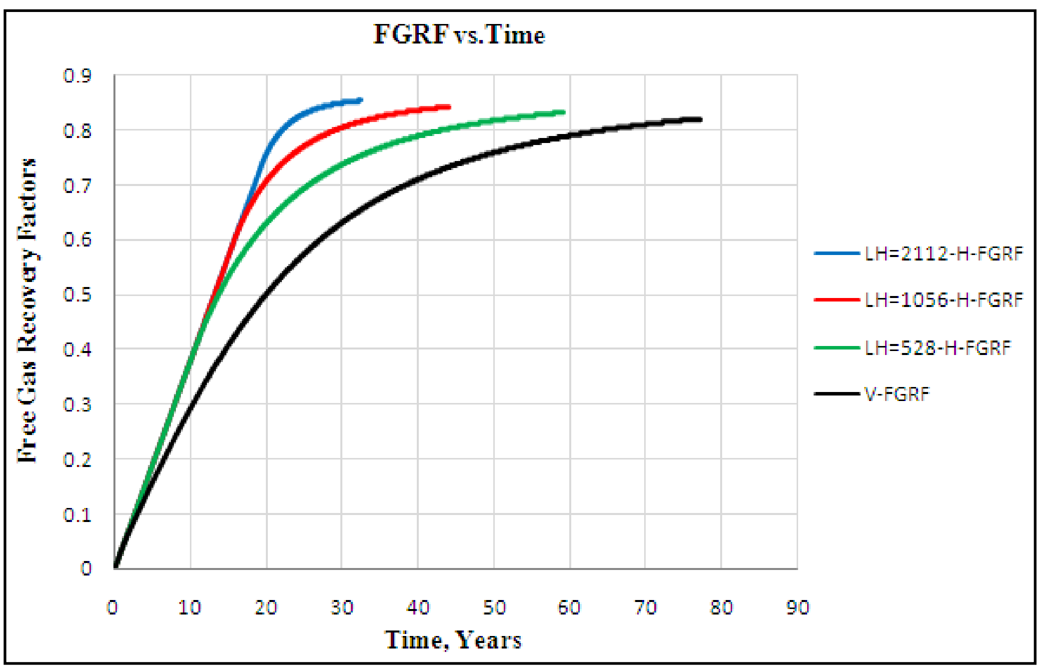

Figure 5.27 Effect of well lengths on free gas recovery factors for horizontal well at A= 160 acres, square drainage area, h=100ft, k_h=1md and k_v/k_h=1

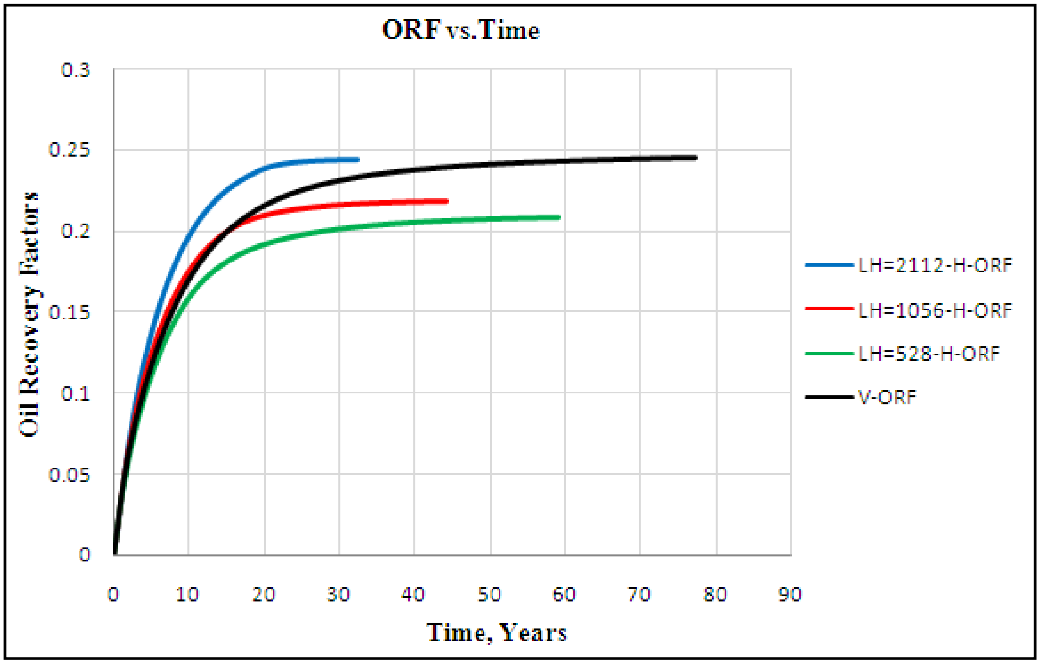

Figure 5.28 Effect of well lengths on oil recovery factors for horizontal well at A=160 acres, square drainage area, h=100ft, k_h=1md and k_v/k_h=1

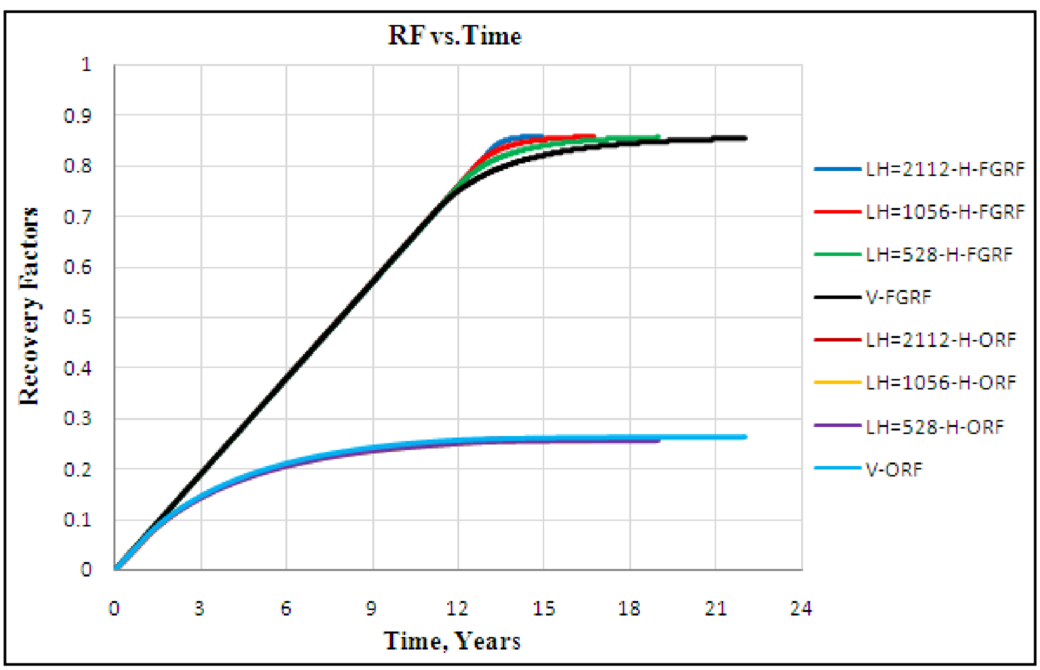

Figure 5.29 Effect of well lengths on free gas and oil recovery factors for horizontal well at A=160 acres, square drainage area, h=100ft, k_h=10 md and k_v/k_h=1

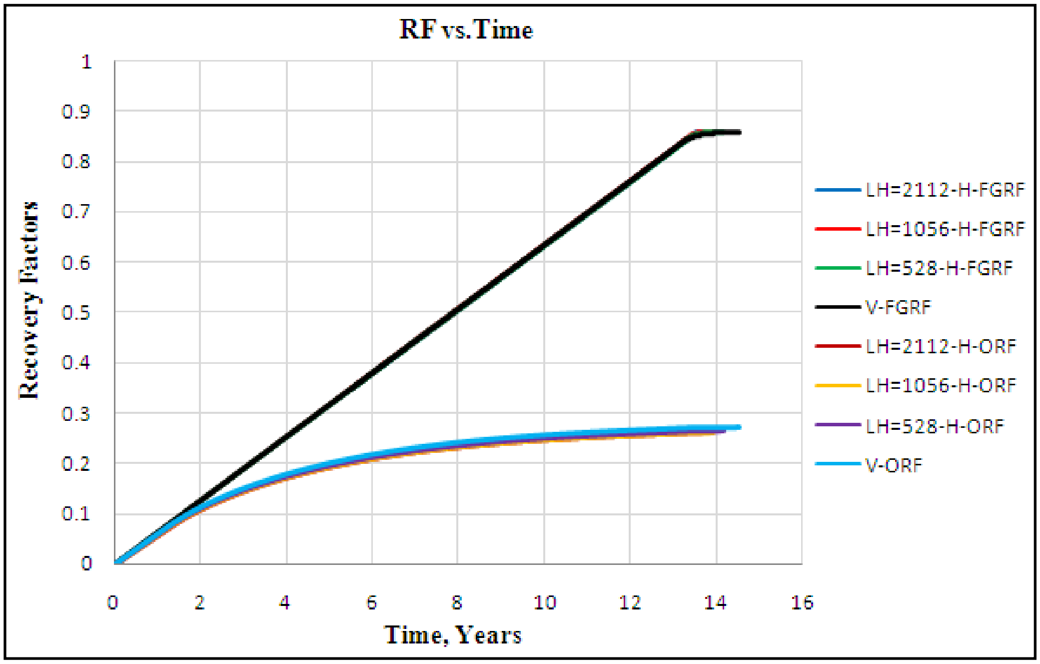

Figure 5.30 Effect of well lengths on free gas and oil recovery factors for horizontal well at A= 160 acres, square drainage area, h=100ft, k_h=100 md and k_v/k_h=1

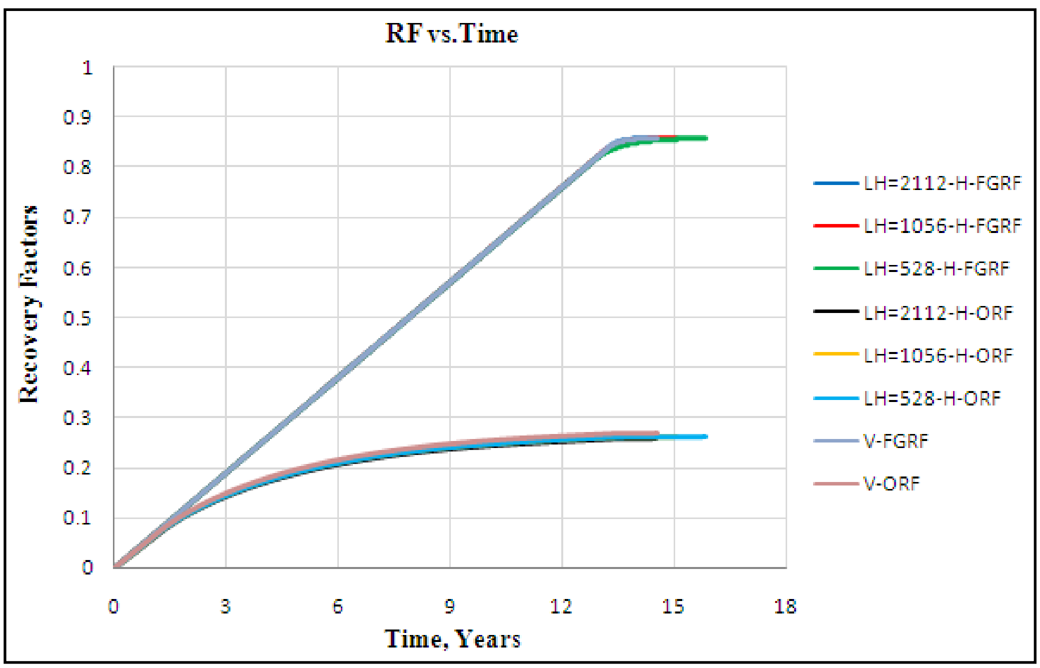

Figure 5.31 Effect of well lengths on free gas and oil recovery factors for horizontal well at A=160 acres, square drainage area, h=100ft, k_h=100 md and k_v/k_h=0.1

5.3 The Effect of Vertical to Horizontal Permeability Ratio

Numerous simulation runs were made for vertical to horizontal permeability ratios of 1:1, 1:2 and 1:10. Figures 5.32 through 5.37 show the effect of vertical to horizontal permeability ratio on the oil and gas recovery factors versus time for a horizontal well with a penetration ratio of 0.2 located in a 160-acre, square drainage area. These figures also show the performance of the vertical well in the same reservoir. Results are shown for horizontal permeabilities of 10 md and 100 md. Figures 5.32 through 5.34 show the results for formation thickness of 25 feet while Figures 5.35 through 5.37 show the results for formation thickness of 100 feet.

These figures and the results shown in Tables A.21 and A.22 indicate that horizontal wells with penetration ratio of 0.2 can be used to develop thin reservoirs (i.e. formation thickness of 25 feet) with horizontal permeability of 10 md or lower for k_v/k_h values of 1 and 0.5; in such cases, the reservoir should be developed with vertical wells for k_v/k_h value of 0.1. Horizontal wells with penetration ratio of 0.2 can also be used to develop thin reservoirs when the horizontal permeability is high (i.e., 100 md), regardless of the value of k_v/k_h.

Vertical wells perform better than horizontal wells with penetration ratio of 0.2 in thick reservoirs (100 feet) when the horizontal permeability is 10 md or higher, regardless of the value of k_v/k_h.

Results shown in Tables A. 21 and A.22 indicate that thick reservoirs (50 feet and higher) with high value of horizontal permeability (100 md.) should be developed with vertical wells, regardless of the value of k_v/k_h and regardless of the value of horizontal well penetration ratio. Results also indicate that as horizontal permeability decreases (such as 10 md), the reservoir should be developed with horizontal wells of high penetration ratio (0.8), regardless of the value of formation thickness, for values of k_v/k_h from 0.5 to 1.0. At horizontal permeability of 1 md, the reservoir should be developed with horizontal wells of penetration ratio of 0.8, for all values of formation thickness and k_v/k_h considered; such reservoirs can be developed with horizontal well penetration ratio of 0.4 for values of k_v/k_h between 0.5 and 1.

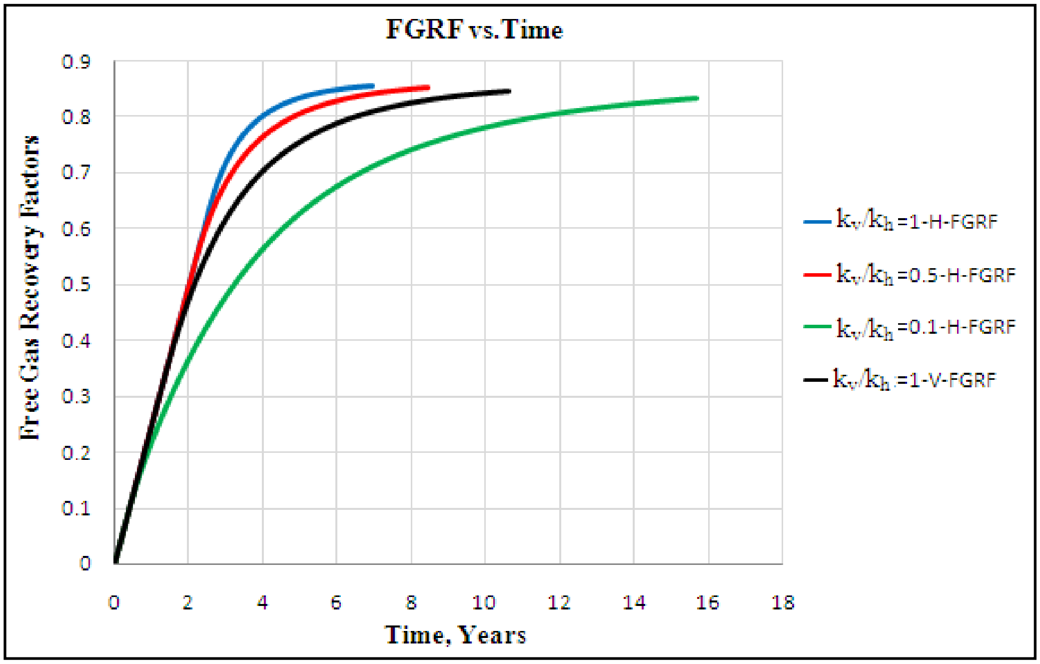

Figure 5.32 Effect of k_v/k_h on free gas recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10 md and L_H=528ft

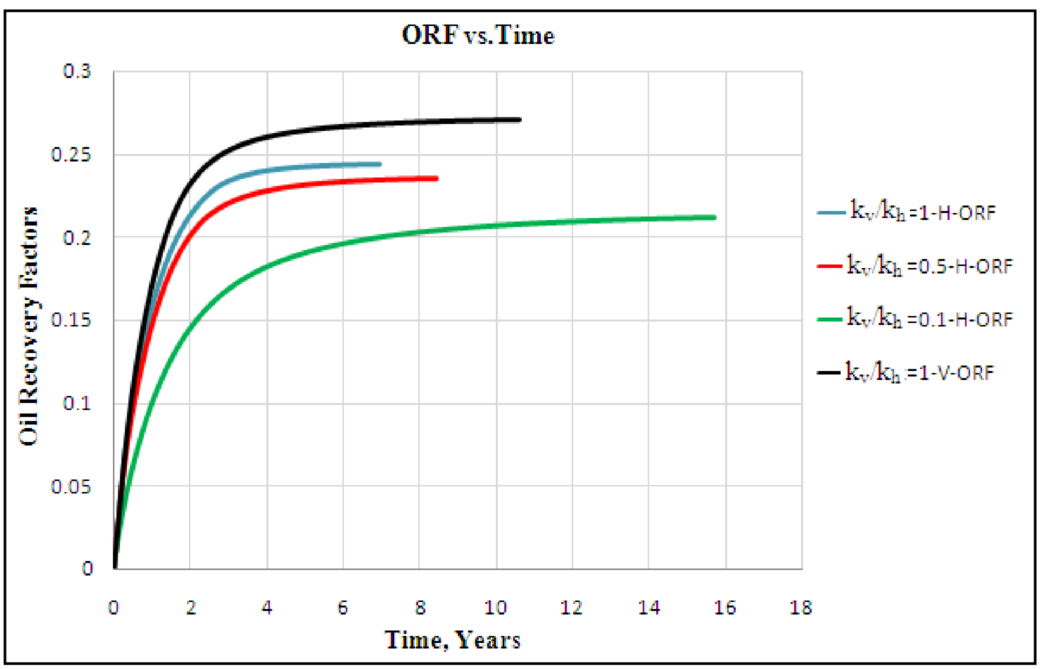

Figure 5.33 Effect of k_v/k_h on oil recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10 md and L_H =528ft

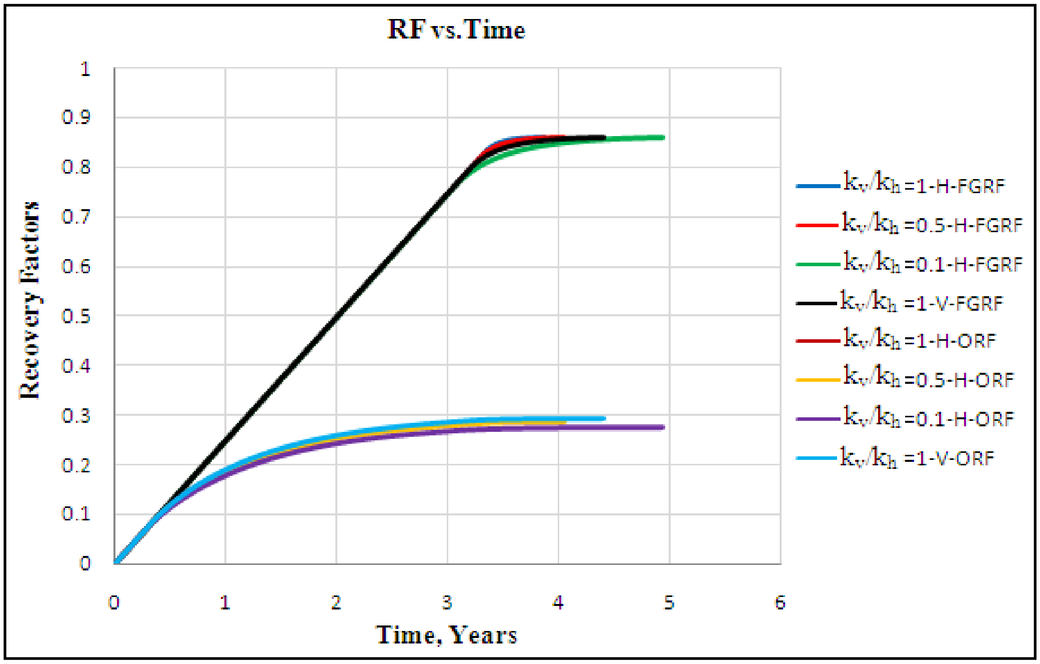

Figure 5.34 Effect of k_v/k_h on free gas and oil recovery factors for horizontal well at A= 160 acres, square drainage area, h=25ft, k_h=100 md and L_H=528ft

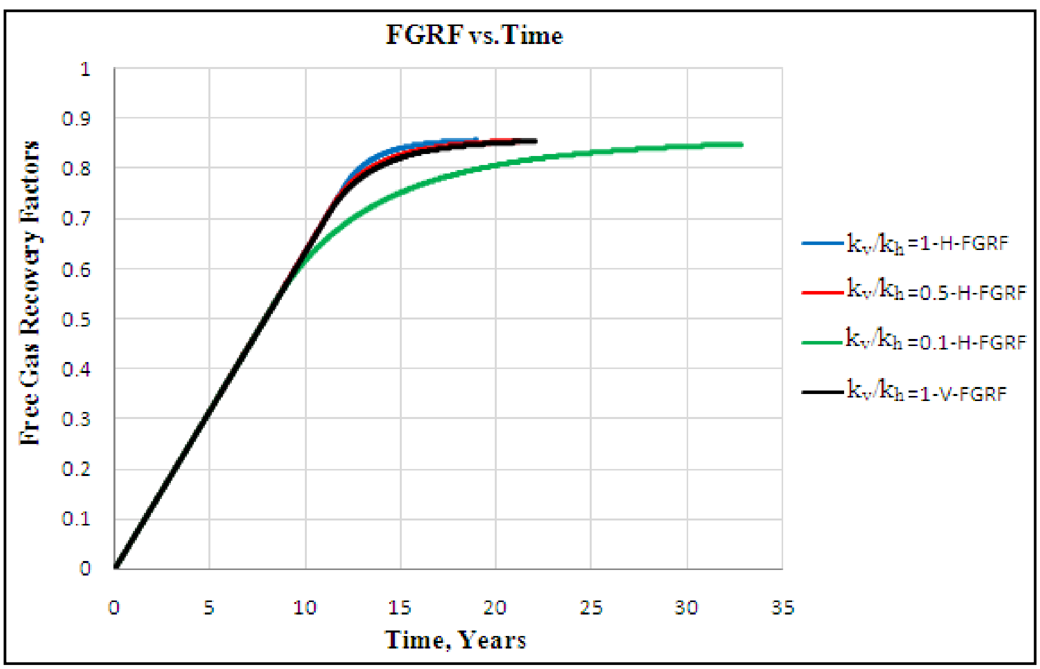

Figure 5.35 Effect of k_v/k_h on free gas recovery factors for horizontal well at A=160 acres, square drainage area, h=100ft, k_h=10 md and L_H =528ft

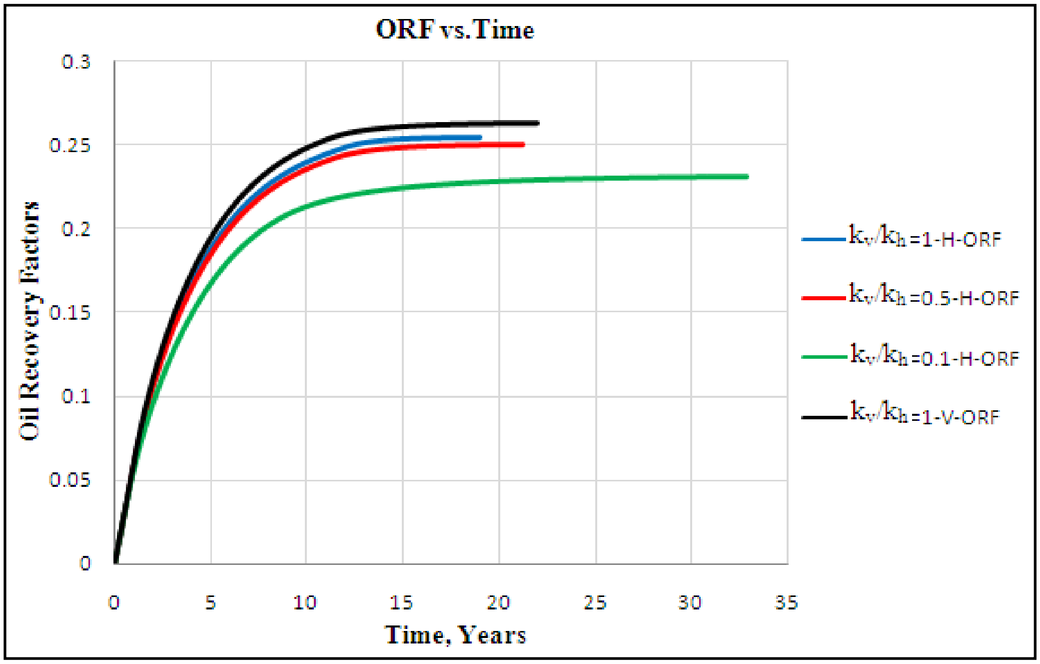

Figure 5.36 Effect of k_v/k_h on oil recovery factors for horizontal well at A=160 acres, square drainage area, h=100ft, k_h=10 md and L_H =528ft

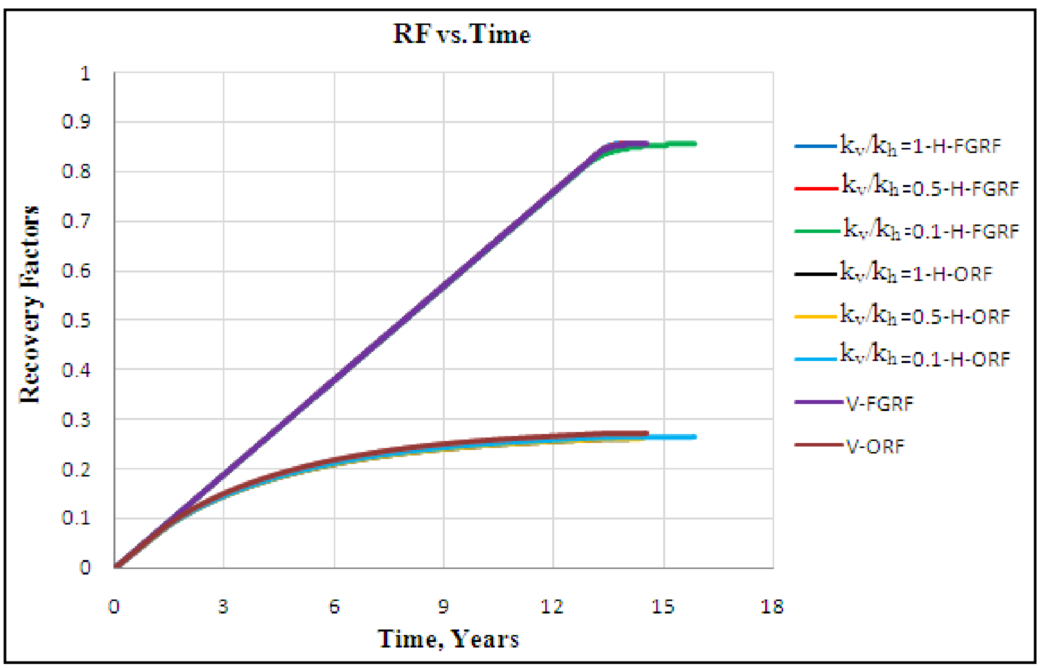

Figure 5.37 Effect of k_v/k_h on free gas and oil recovery factors for horizontal well at A=160 acres, square drainage area, h=100ft, k_h=100 md and L_H =528ft

5.4 The Effect of Reservoir Thickness

In order to study the effect of reservoir thickness on oil and gas recovery factors for horizontal and vertical wells, numerous reservoir simulation runs were made with different formation thicknesses, keeping all other well and reservoir parameters constant. Formation thicknesses of 25, 50 and 100 ft were considered as shown in Figures 5.38 through 5.43. Figures 5.38 & 5.40 show the results for 160-acres square drainage area, horizontal permeability of 10 md, and k_v/k_h value of 1. Figures 5.41 & 5.43 show the results for the 160-acres square drainage area, horizontal permeability of 100 md, and k_v/k_h value of 1.

Results shown in Figures 5.38 through 5.40 and in Tables A.21 and A.22 indicate that for reservoirs with horizontal permeability of 10 md and lower and k_v/k_h value of 1, a horizontal well with a penetration ratio of 0.8 performs better than a vertical well, for all values of formation thicknesses considered.

Results shown in Figures 5.41 through 5.43 and in Tables A.21 and A.22 indicate that for reservoirs with horizontal permeability of 100 md and k_v/k_h value of 1, a vertical well performs almost the same as a horizontal well with a penetration ratio of 0.8, for all values of formation thicknesses considered. Therefore, in these cases, the reservoir should be developed with vertical wells.

Results shown in Tables A.21, A.22, and A.23 show that for reservoirs with horizontal permeability of 1 md., the reservoir should be developed with horizontal well of penetration ratio greater than 0.4, for k_v/k_h values between 0.5 and 1; for these reservoirs, the reservoir should be developed with vertical well when k_v/k_h value is low (0.1). In reservoirs with horizontal permeability of 1 md, horizontal wells with penetration ratio of

0.2 have advantage over vertical wells in reservoirs with thickness less than 50 feet, for k_v/k_h values between 0.5 and 1 and in reservoirs with thickness of 100 feet only when the k_v/k_h is near 1.

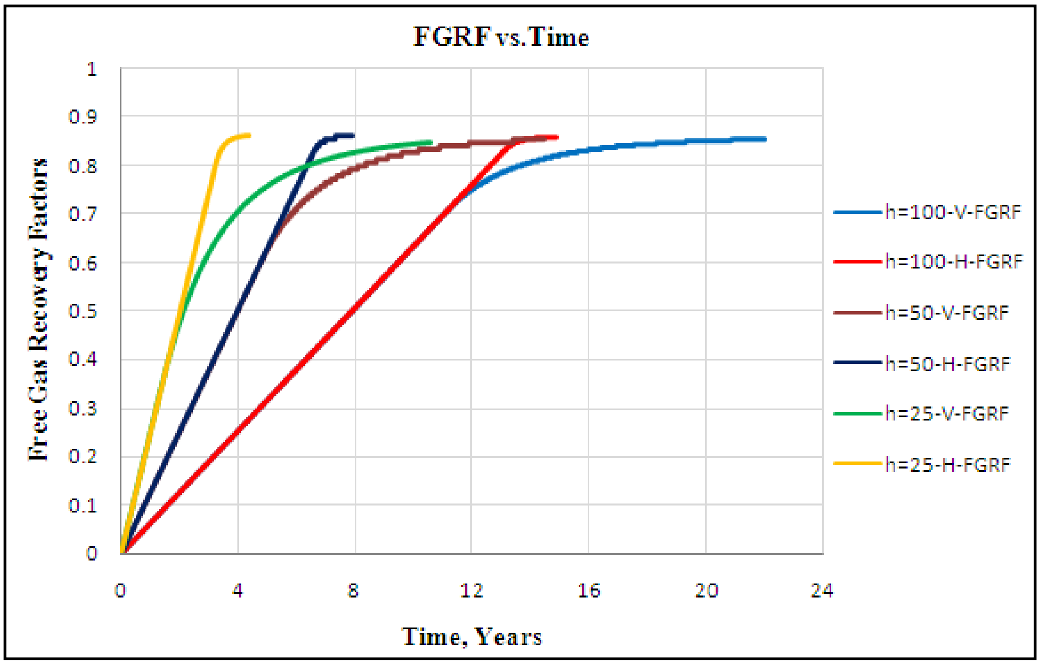

Figure 5.38 Effect of reservoir thickness on free gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, k_h=10md, L_H=2112ft and k_v/k_h=1

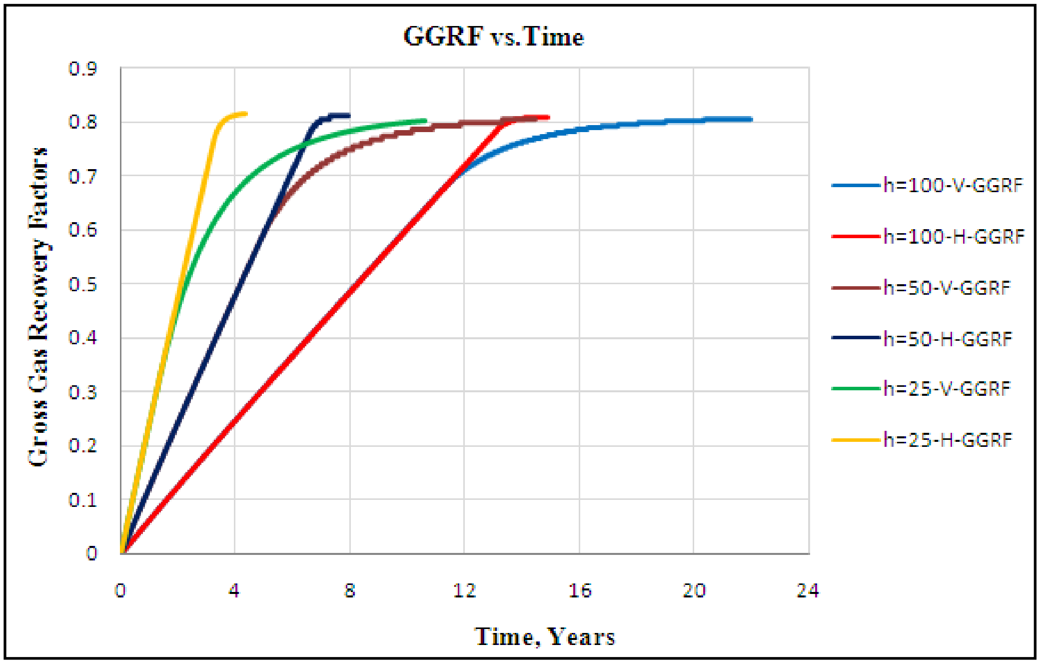

Figure 5.39 Effect of reservoir thickness on gross gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, k_h=10md, L_H=2112ft and k_v/k_h=1

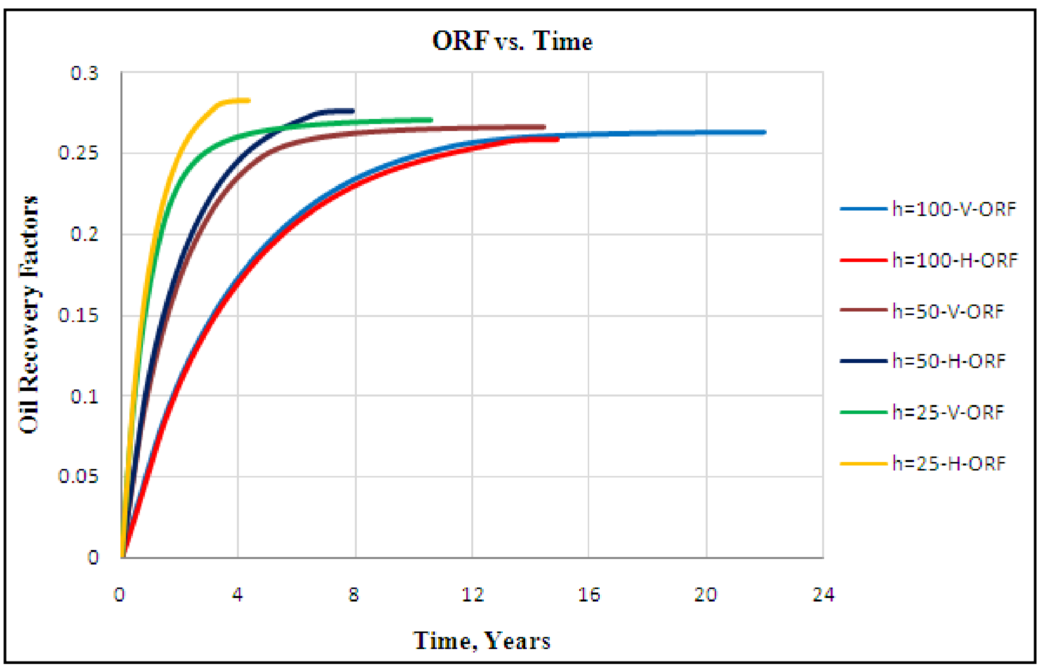

Figure 5.40 Effect of reservoir thickness on oil recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, k_h=10md, L_H=2112ft and k_v/k_h=1

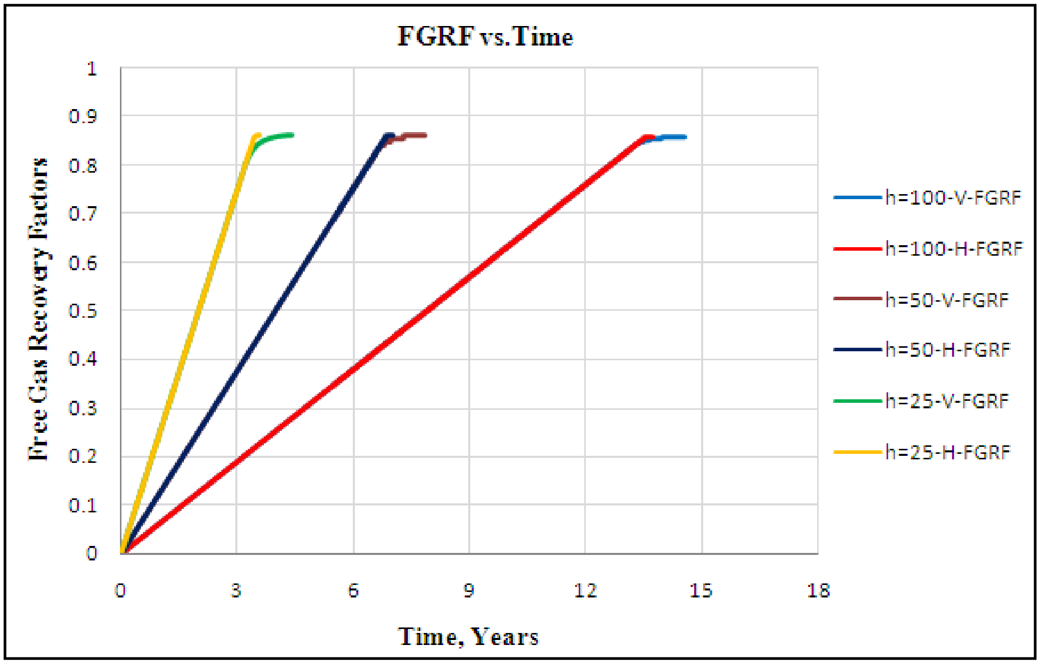

Figure 5.41 Effect of reservoir thickness on free gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, k_h=100md, L_H=2112ft and k_v/k_h=1

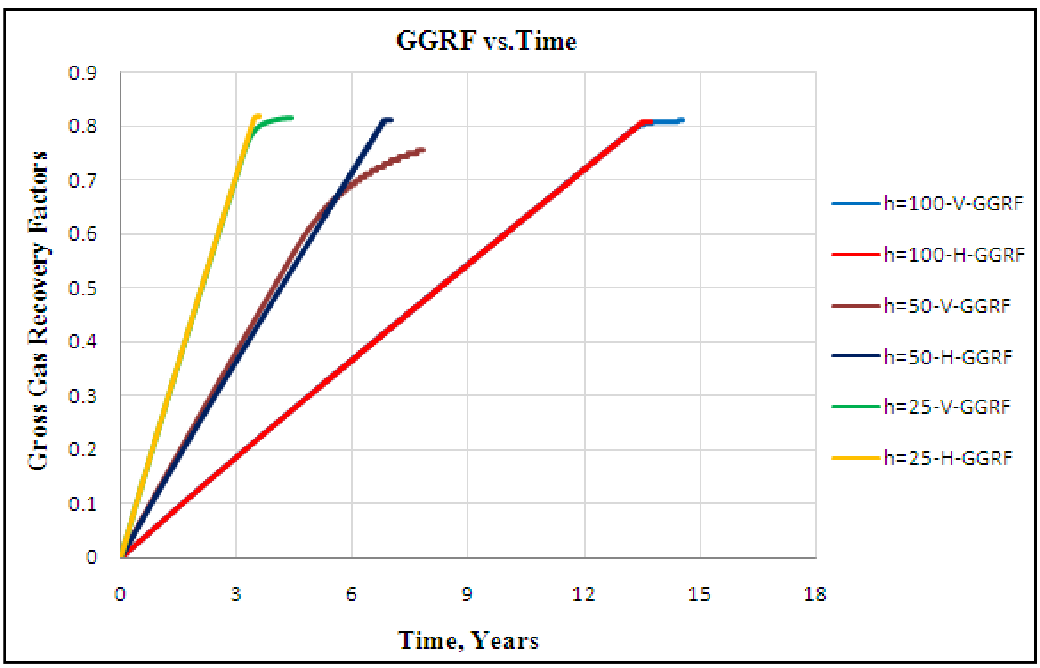

Figure 5.42 Effect of reservoir thickness on gross gas recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, k_h=100md, L_H=2112ft and k_v/k_h=1

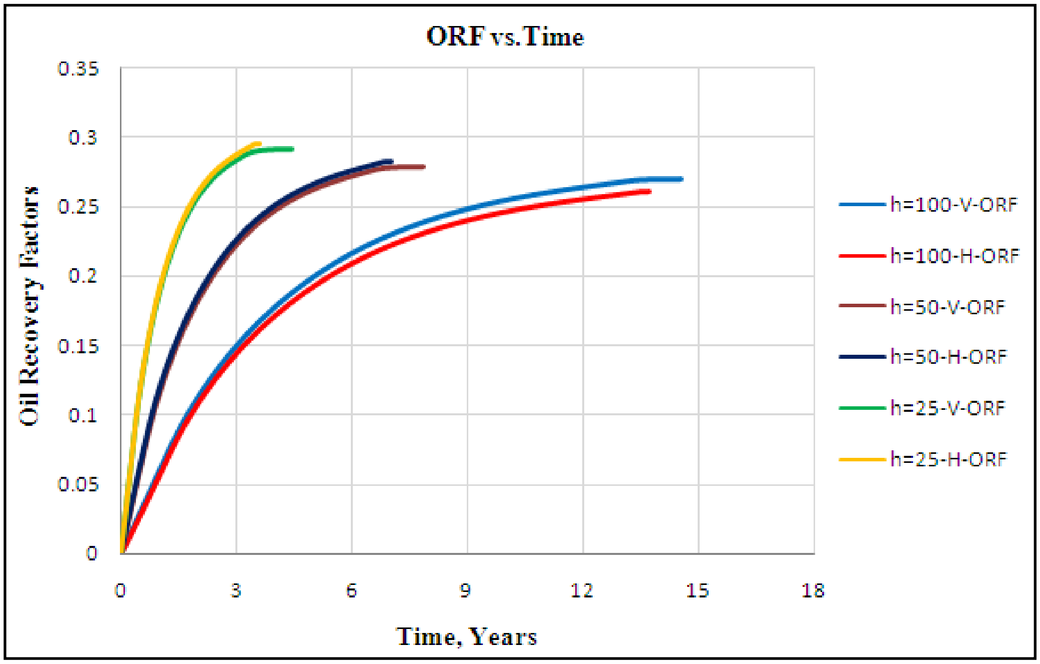

Figure 5.43 Effect of reservoir thickness on oil recovery factors for vertical and horizontal wells at A=160 acres, square drainage area, k_h=100md, L_H=2112ft and k_v/k_h=1

5.5 The Effect of Drainage Area Size and Shape

Two drainage area sizes (160 acres and 80 acres) and two drainage area shapes (square and 2:1 rectangle) were considered in this study in order to investigate the effect of drainage area size and shape on the performance horizontal and vertical wells. Results are shown in Figures 5.44 through 5.52.

As shown in these figures, for horizontal well with penetration ratio of 0.8 located in a reservoir with k_v/k_h value of 1, the drainage area size has no effect on the performance of horizontal wells and on the performance of vertical wells in regards to oil and gas recovery factors; this statement is valid for all values of horizontal permeabilities and formation thicknesses considered. However, with doubling the drainage area size, the time to reach the ultimate recovery almost doubles for both horizontal and vertical wells, for the cases shown in these figures.

As shown in Figures 5.50 through 5.52, the drainage area shape has no effect on the performance of horizontal wells and on the performance of vertical wells with regards to the ultimate oil and gas recovery factors, for all values of horizontal permeabilities and formation thicknesses considered.

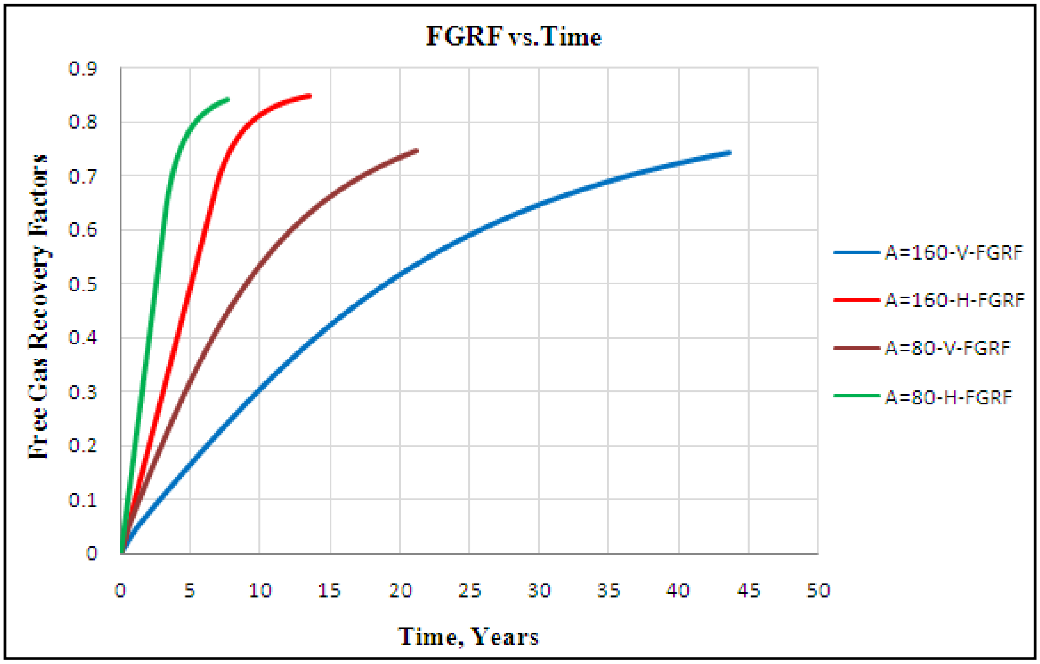

Figure 5.44 Effect of drainage area size on free gas recovery factors for vertical and horizontal wells at h=25ft, square drainage area, k_h=1md, L_H =2112ft and k_v/k_h=1

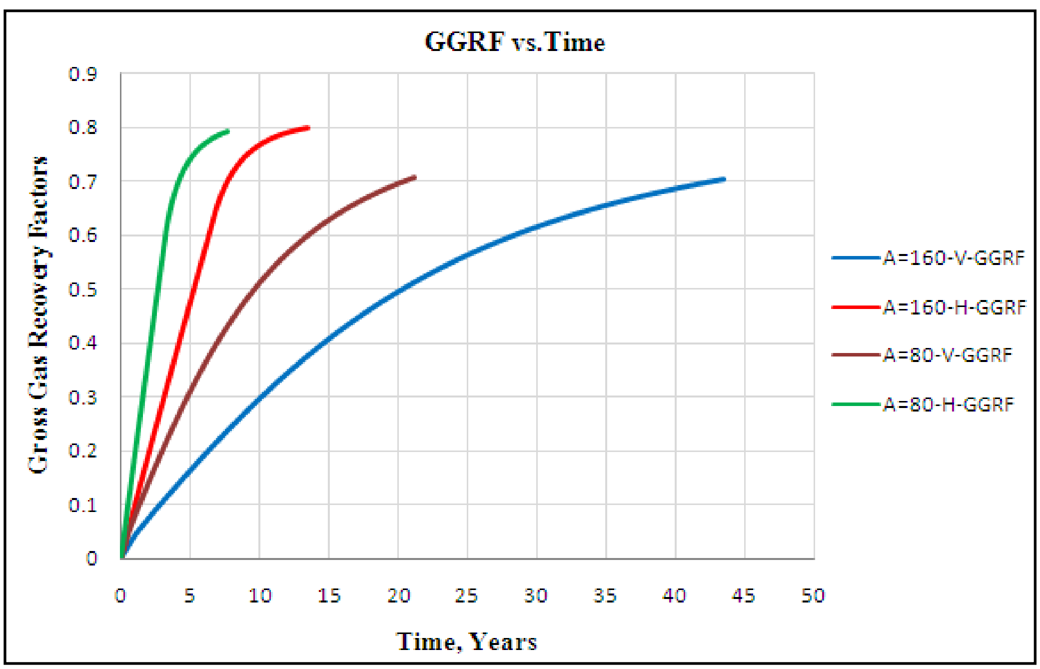

Figure 5.45 Effect of drainage area size on gross gas recovery factors for vertical and horizontal wells at h=25ft, square drainage area, k_h= 1md, L_H =2112ft and k_v/k_h=1

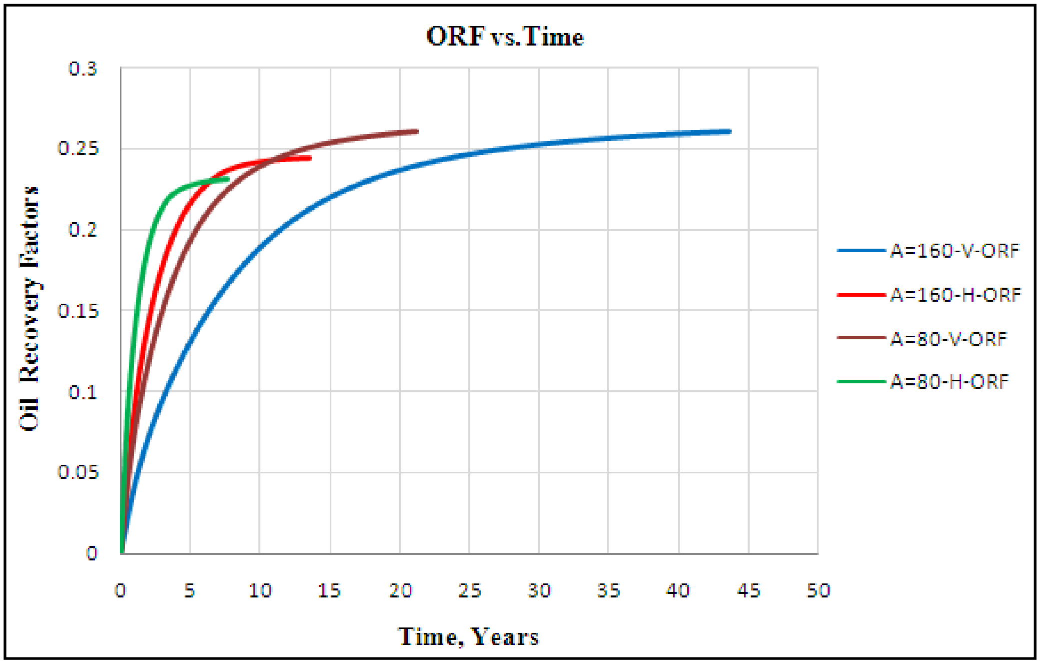

Figure 5.46 Effect of drainage area size on oil recovery factors for vertical and horizontal wells at h=25ft, square drainage area, k_h=1md, L_H =2112ft and k_v/k_h=1

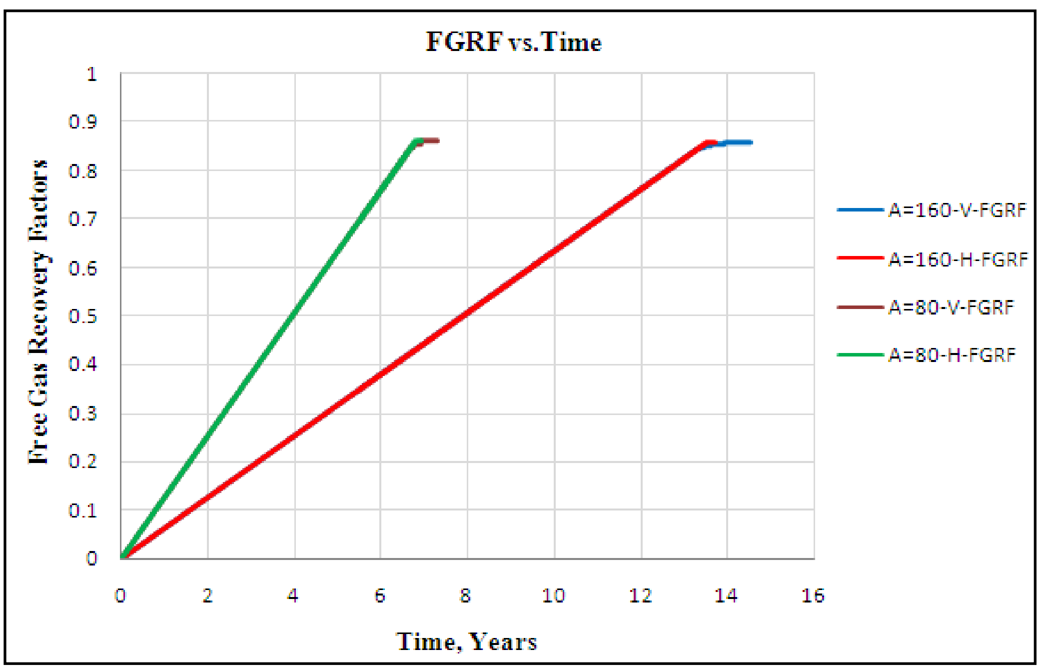

Figure 5.47 Effect of drainage area size on free gas recovery factors for vertical and horizontal wells at h=100ft, square drainage area, k_h=100md, L_H =2112ft and k_v/k_h=1

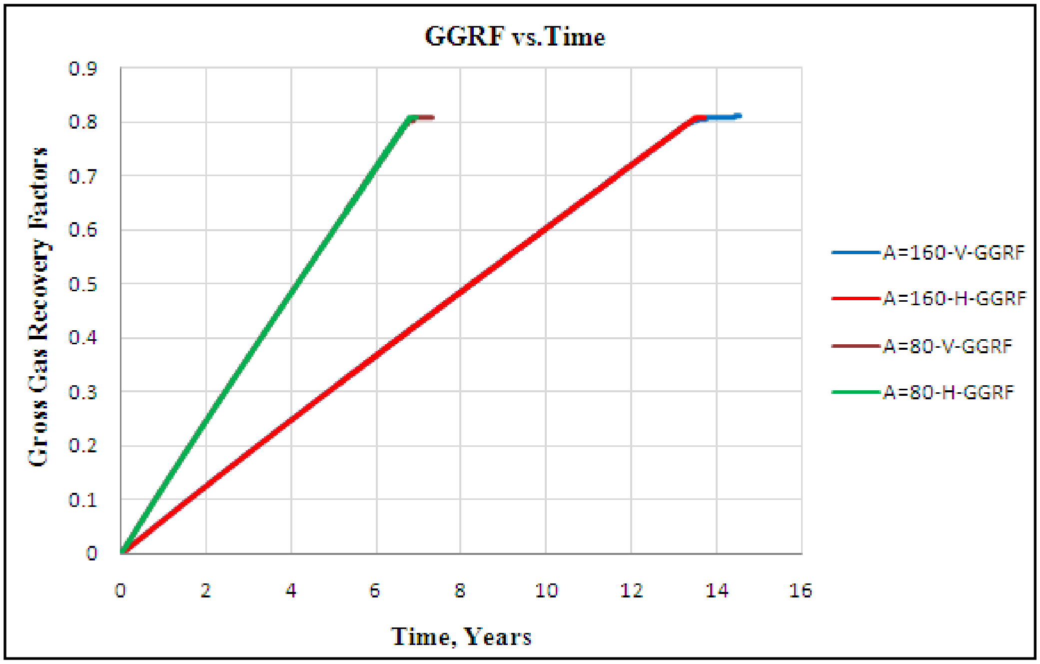

Figure 5.48 Effect of drainage area size on gross gas recovery factors for vertical and horizontal wells at h=100ft, square drainage area, k_h=100md, L_H =2112ft and k_v/k_h=1

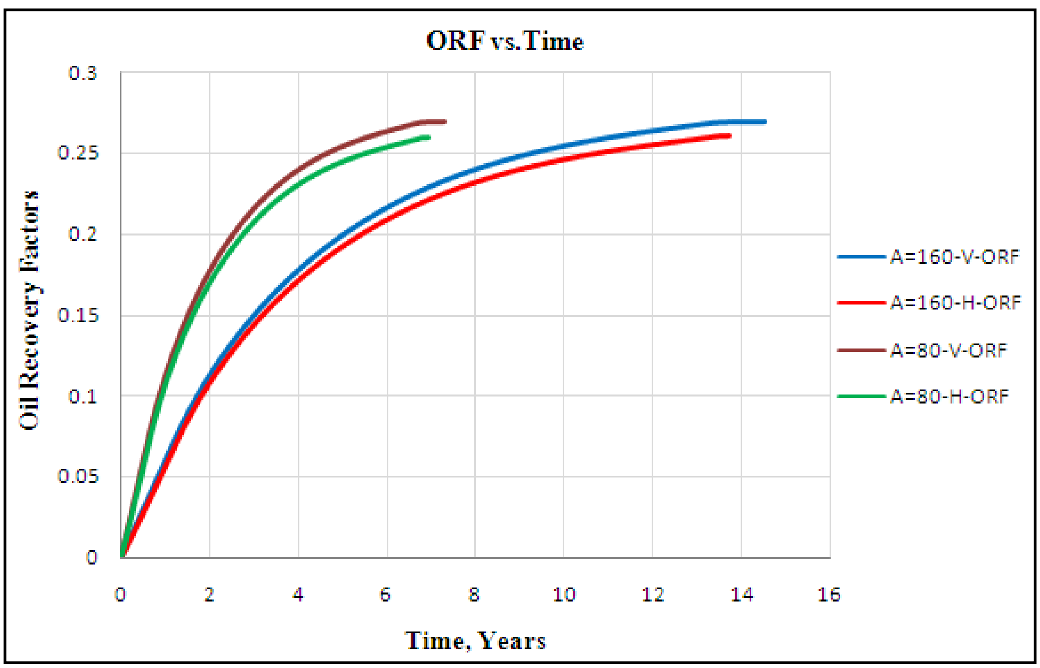

Figure 5.49 Effect of drainage area size on oil recovery factors for vertical and horizontal wells at h=100ft, square drainage area, k_h=100md, L_H=2112ft and k_v/k_h=1

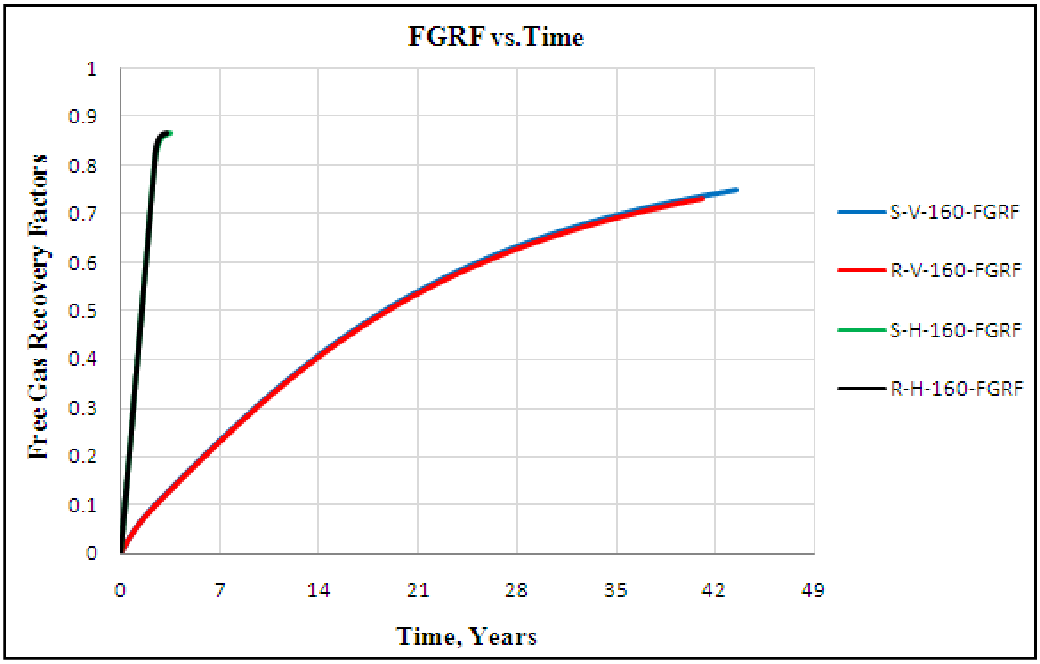

Figure 5.50 Effect of drainage area shape on free gas recovery factors for vertical and horizontal wells A=160 acres, h=25ft, k_h=1md, L_H =2112ft and 2992 ft and k_v/k_h=1

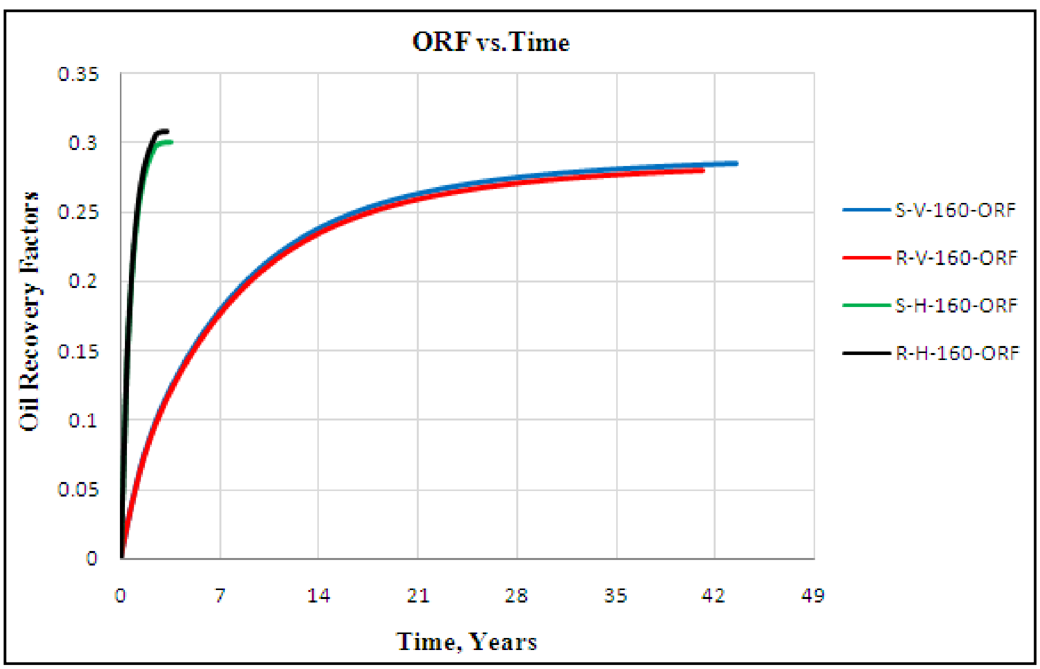

Figure 5.51 Effect of drainage area shape on oil recovery factors for vertical and horizontal wells A=160 acres, h=25ft, k_h= 1md, L_H=2112ft and 2992 ft and k_v/k_h=1

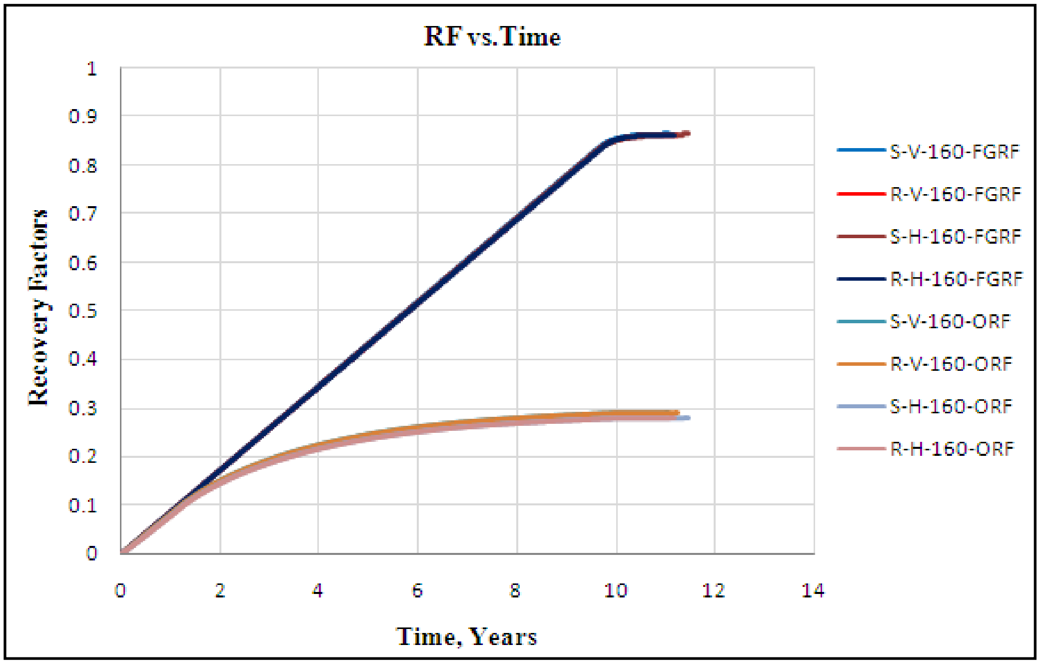

Figure 5.52 Effect of drainage area shape on free gas and oil recovery factors for vertical and horizontal wells A=160 acres, h=100ft, k_h=100md, L_H=2112ft and 2992ft and k_v/k_h=1

5.6 Oil Distribution Map

When the reservoir pressure drops below the dew-point pressure, significant condensate saturation builds up around the wellbore. Condensate blockage near the well may cause a significant loss in well deliverability for low-to-moderate permeability reservoirs. Figures 5.53 through 5.58 compare the oil saturation distribution in the reservoir at abandonment conditions for the horizontal and vertical wells. Figure 5.53 and 5.54 show oil distribution map for a horizontal well located in a 160-acres square drainage area, with a formation thickness of 25 feet, horizontal permeability of 100 md, horizontal penetration ratio of 0.8, and k_v/k_h value of 1. Figure 5.55 and 5.56 show oil distribution map for a horizontal well located in a 160-acres square drainage area with a formation thickness of 25 feet, horizontal permeability of 1 md, horizontal well penetration ratio of 0.2, and k_v/k_h value of 1. Oil distribution map for a vertical well located in a 160-acres square drainage area, with a formation thickness of 100 feet and horizontal permeability of 100 md is shown in Figure 5.57 and the oil distribution map for a vertical well located in a 160-acres square drainage area with a formation thickness of 25 feet and horizontal permeability of 1 md is shown in Figure 5.58.

Figures 5.53 through 5.56 show that horizontal wells with penetration ratio of 0.2 cause more liquid drop-out in larger part of the drainage area than do horizontal wells with penetration ratio of 0.8.

Figures 5.57 and 5.58 show that for low formation thickness and low horizontal permeability, there is liquid drop-out throughout the drainage area of the vertical well while for low formation thickness and high horizontal permeability, the liquid drop-out is in an area near the vertical well.

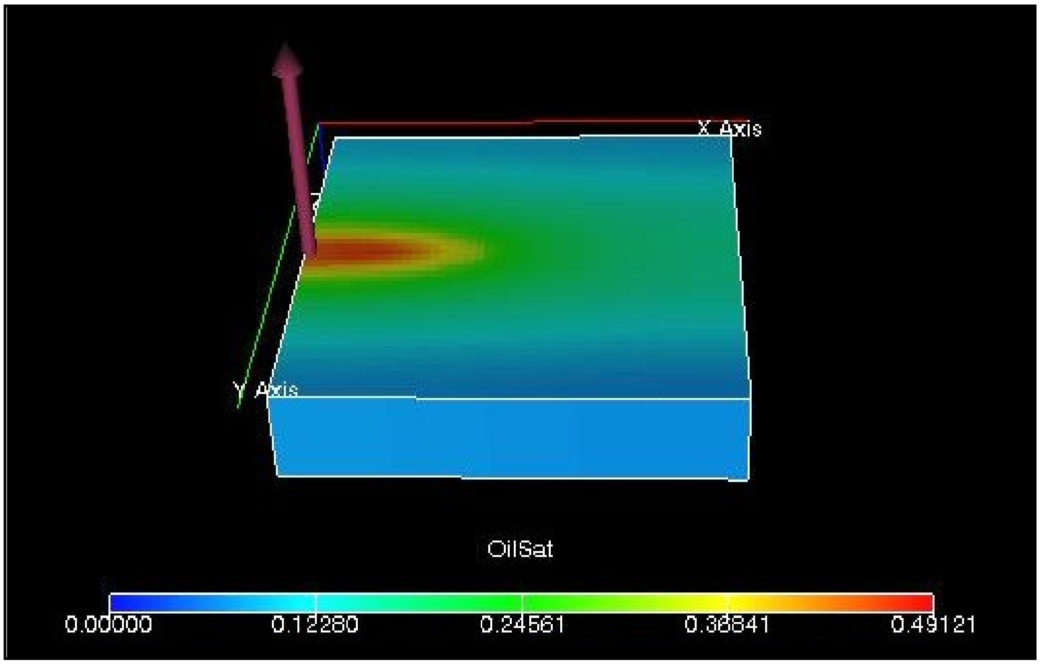

Figure 5.53 Oil distribution map for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=100md, L_H=2112ft and k_v/k_h=1

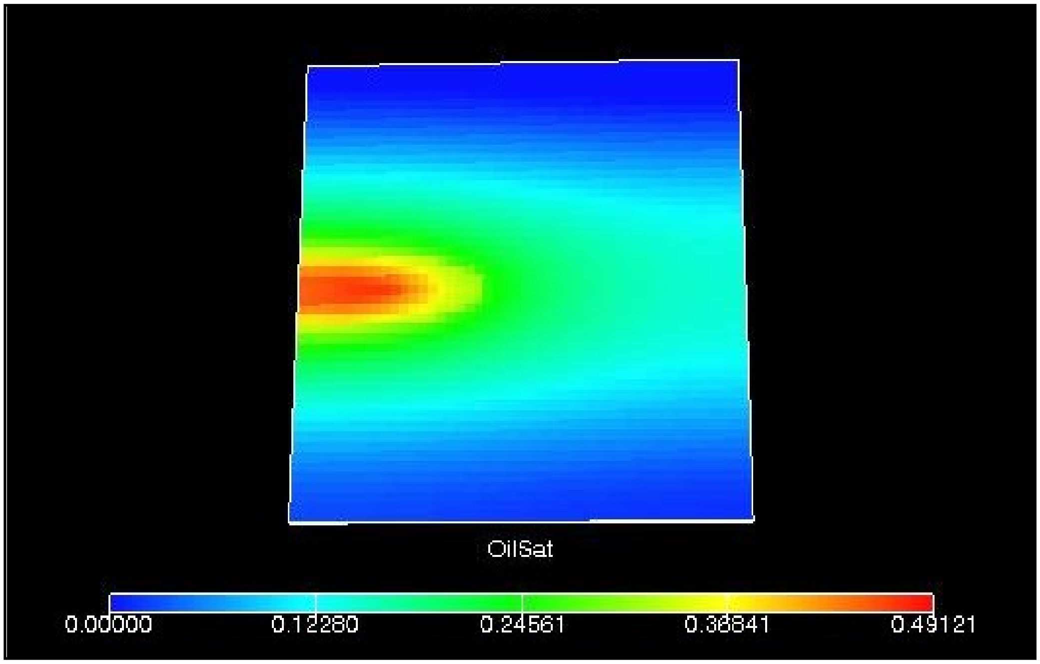

Figure 5.54 Oil distribution map for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=100md, L_H =2112ft and k_v/k_h=1

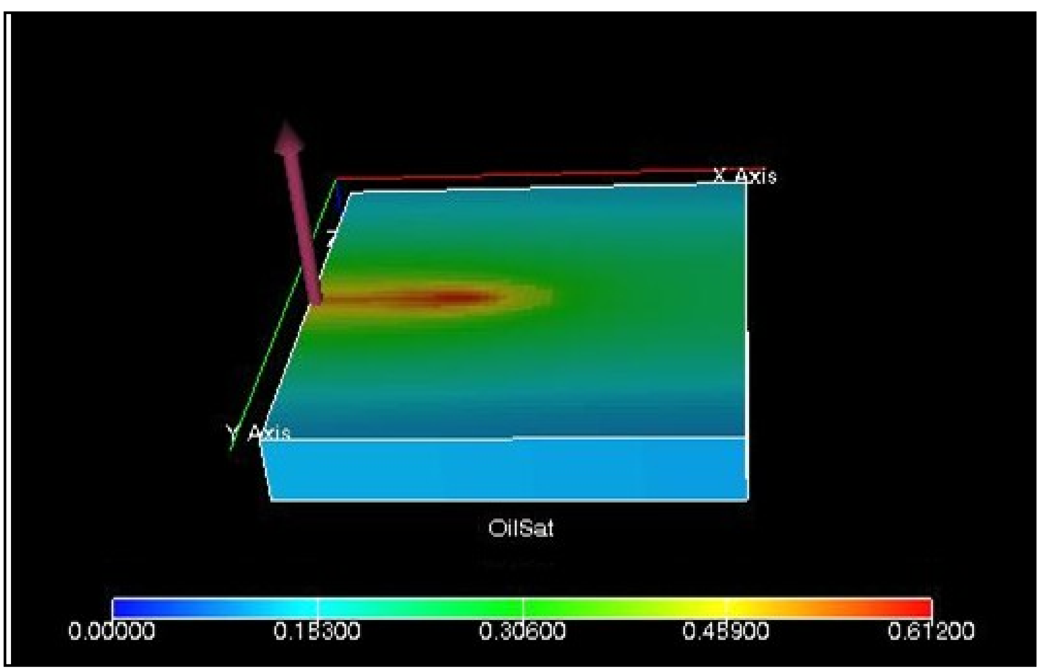

Figure 5.55 Oil distribution map for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1 md, L_H =528ft and k_v/k_h=1

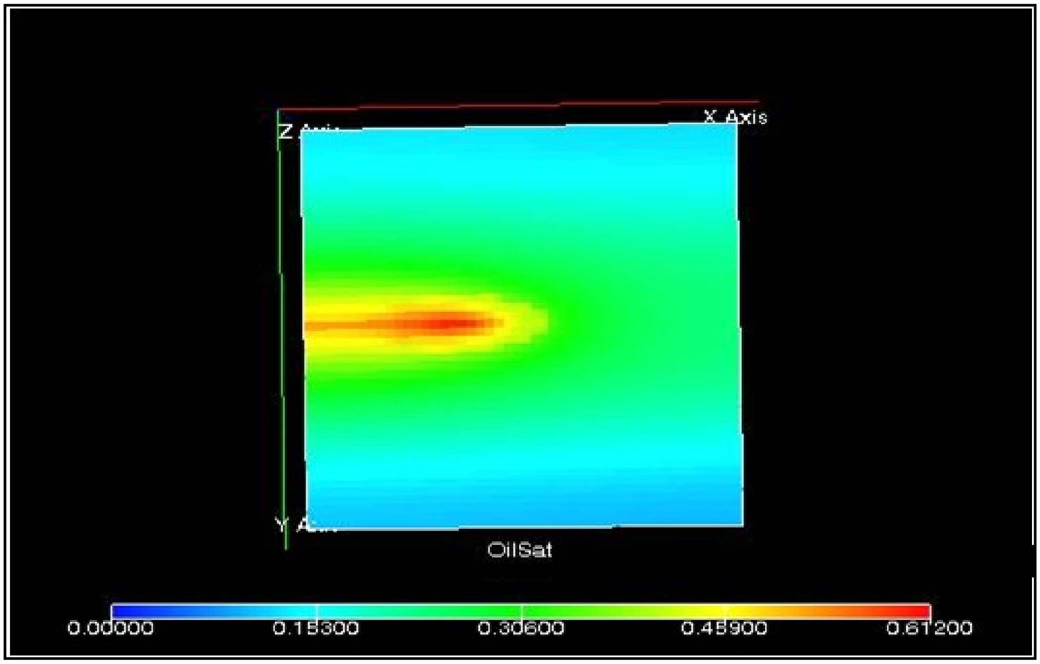

Figure 5.56 Oil distribution map for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1 md, L_H =528ft and k_v/k_h=1

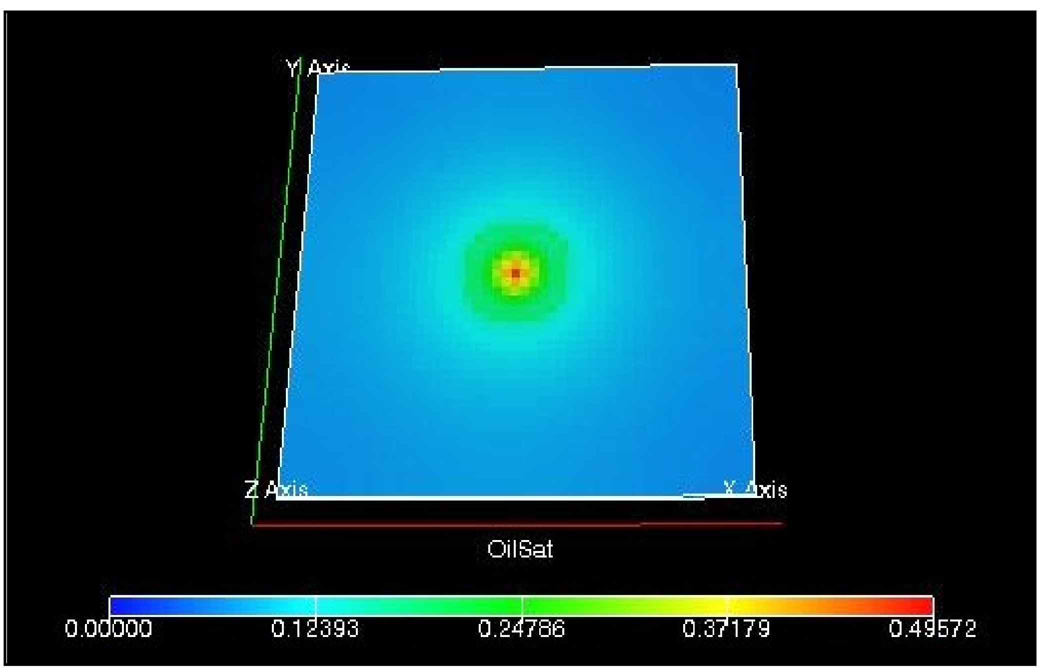

Figure 5.57 Oil distribution map for vertical well at A=160 acres, square drainage area, h=25ft and k_h=100md

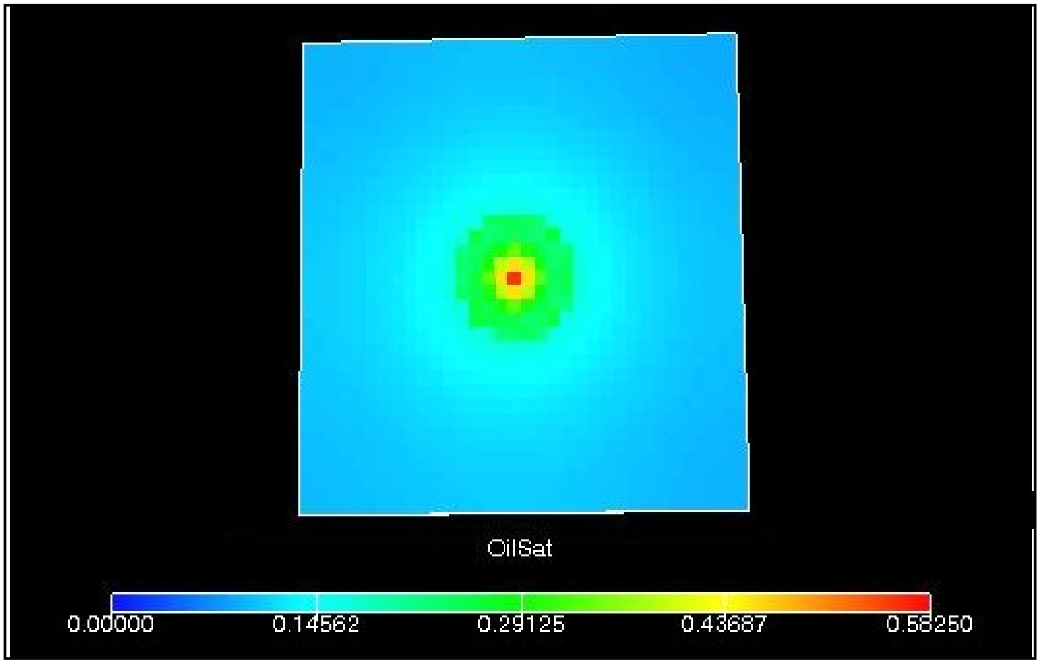

Figure 5.58 Oil distribution map for vertical well at A=160 acres, square drainage area, h=25ft and k_h=1md

5.7 Simple Equations for Determination of Time to Reach Abandonment Conditions

In this section, an attempt will be made to obtain a relationship between well and reservoir parameters and the time to reach abandonment conditions for both horizontal and vertical wells. The use of such equations would enable the petroleum engineer to quickly estimate the time that it will take to produce the recoverable reserves, without having to perform a time-consuming reservoir simulation study. Various attempts to develop reliable equations were made and it was determined that the time to reach abandonment conditions correlates very well with formation thickness in a given reservoir for both vertical wells and horizontal wells of a given penetration ratio, as shown in Figures 5.59 through 5.65. Figures 5.59 through 5.64 are for horizontal wells located in a 160-acre, square drainage area with horizontal permeabilities of 1, 10, and 100 md for k_v/k_h values of 1, 0.5 and 0.1. Figure 5.65 shows the results for the vertical wells located in the same reservoirs. Table 5.1 shows the values of R^2, providing an indication of how good the correlation equations are. As shown, the R^2 for the correlation equations are all equal to 1 except for two equations which have R^2 value of 0.999. In this table, t is in years and h is in feet. To our knowledge, this is the first time such correlations have been obtained for determining the time to reach abandonment conditions. These results show that doubling the formation thickness (i.e., doubling the reservoir volume) does not double the time to reach abandonment conditions; in other words, it does not double the time to produce the recoverable reserves.

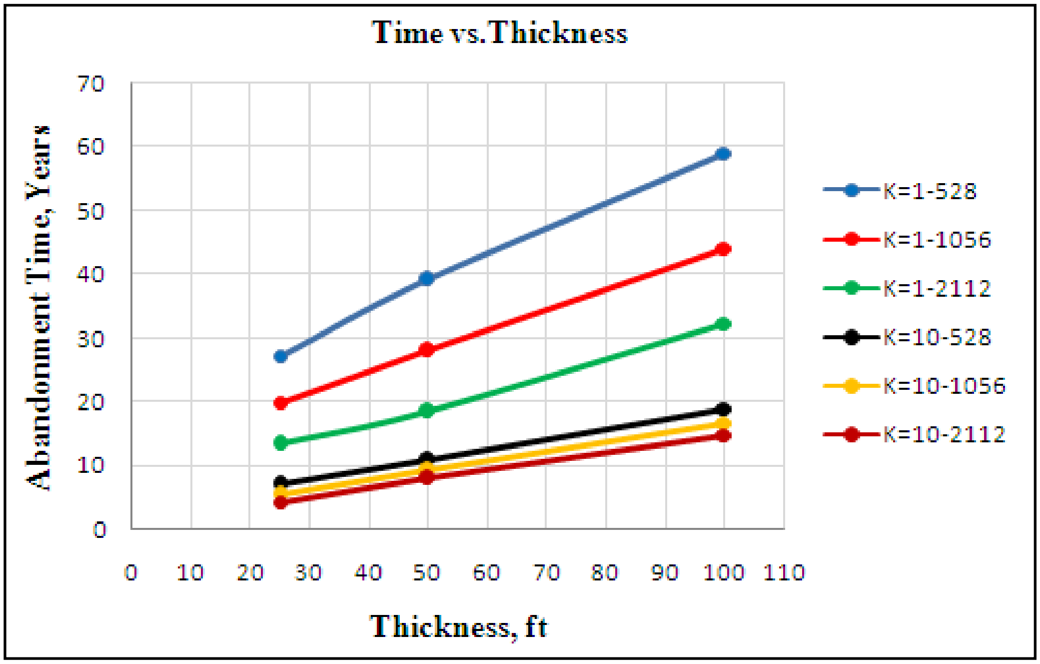

Figure 5.59 Abandonment time prediction for horizontal wells as a function of thickness by this work at A=160 acres, square drainage area, k_h=1 and10 md, and k_v/k_h=1

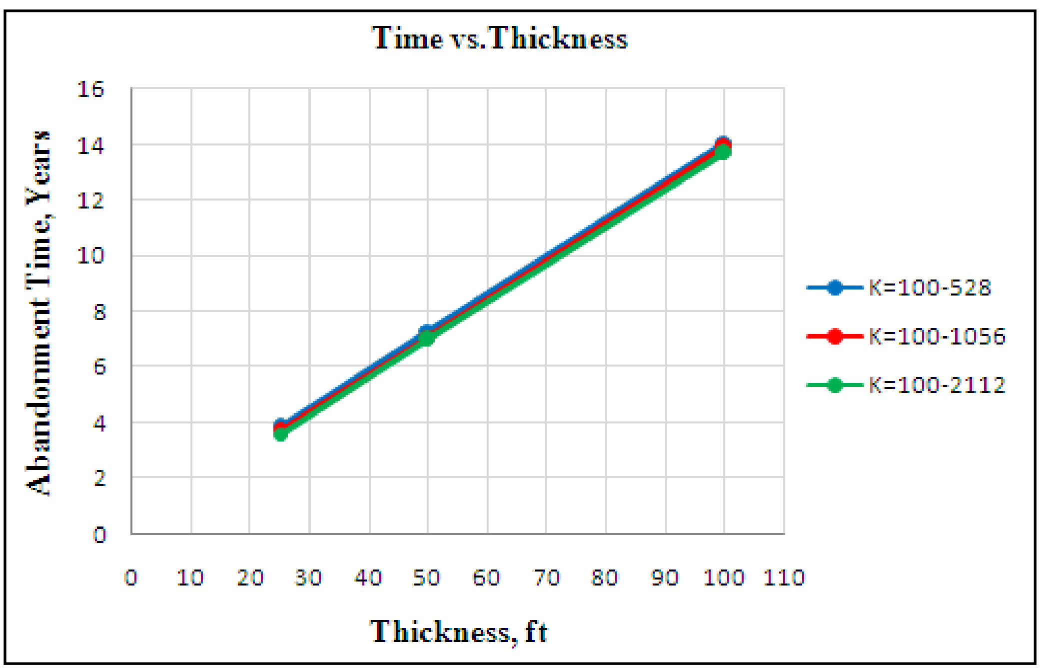

Figure 5.60 Abandonment time prediction for horizontal wells as a function of thickness by this work at A=160 acres, square drainage area, k_h= 100md and k_v/k_h=1

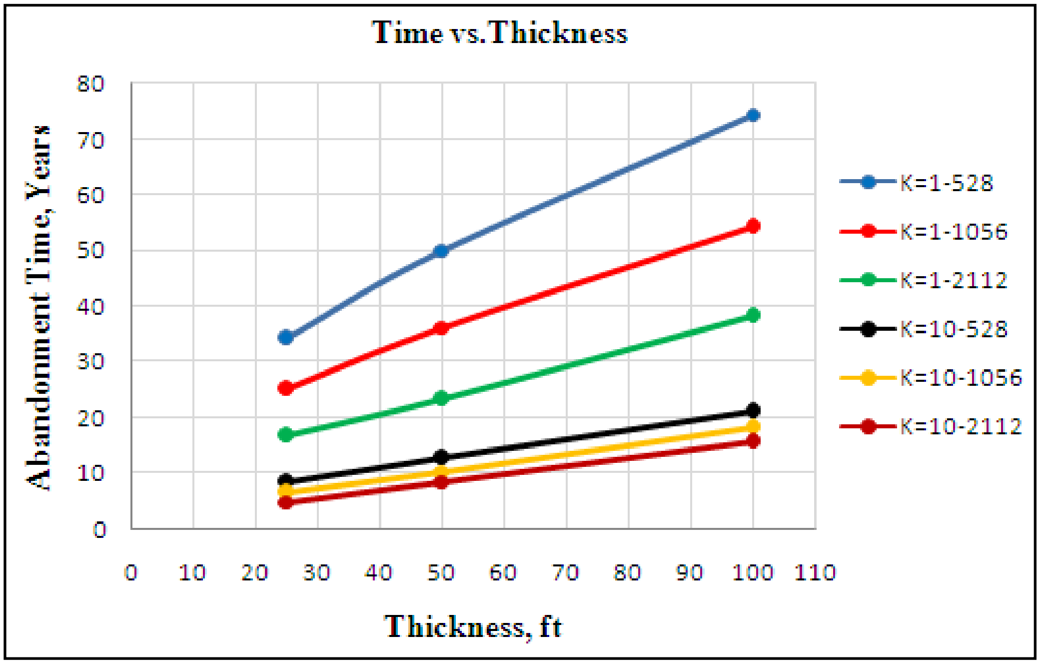

Figure 5.61 Abandonment time prediction for horizontal wells as a function of thickness by this work at A=160 acres, square drainage area, k_h=1 and10md and k_v/k_h=0.5

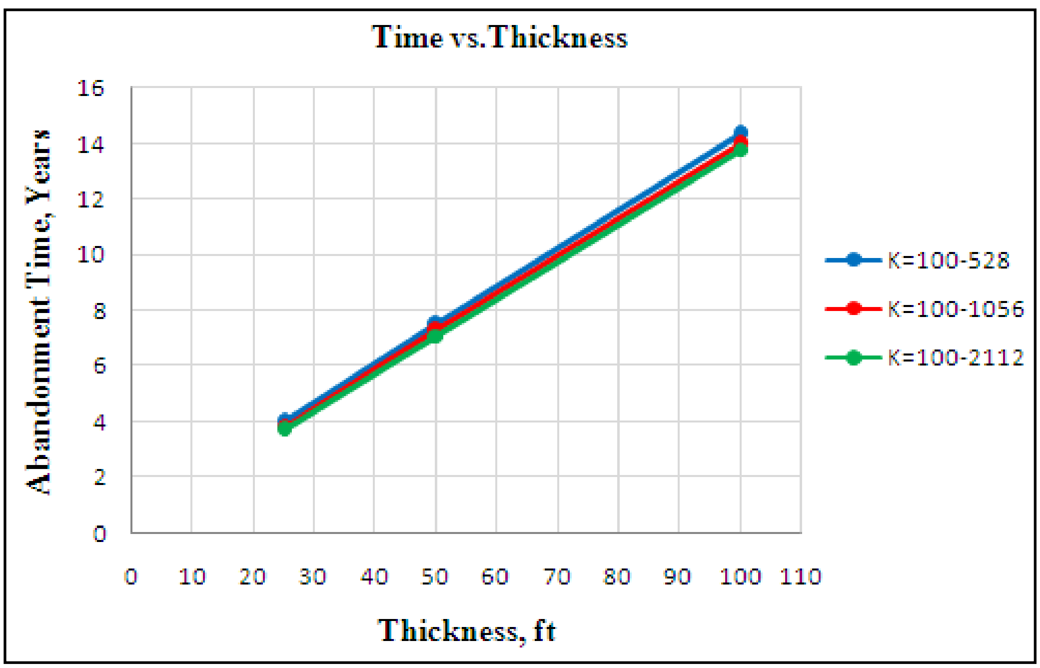

Figure 5.62 Abandonment time prediction for horizontal wells as a function of thickness by this work at A=160 acres, square drainage area, k_h=100md and k_v/k_h=0.5

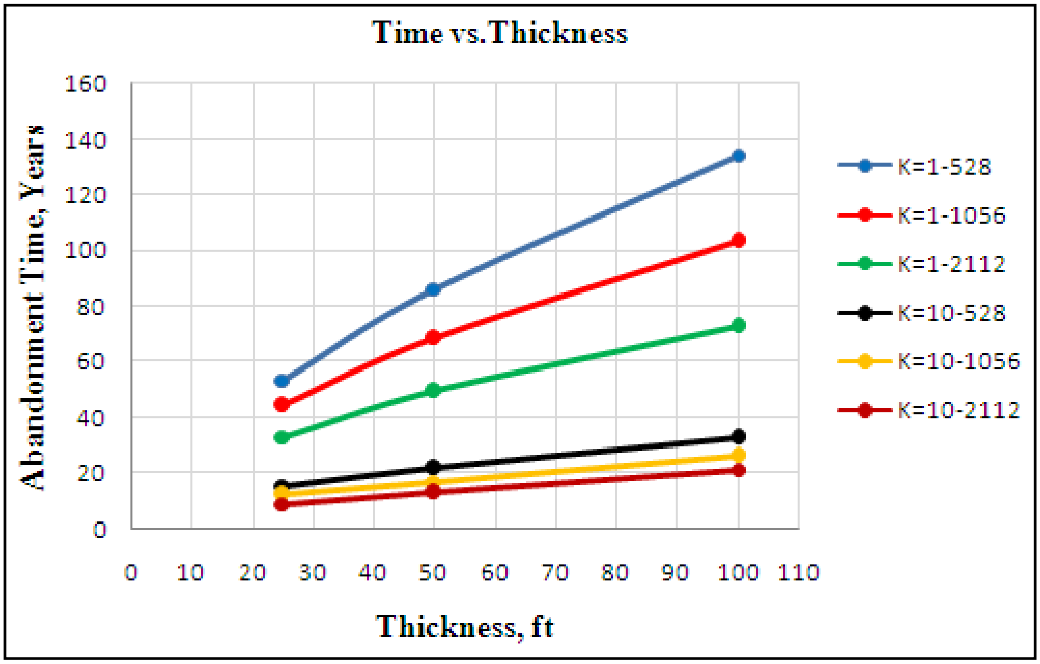

Figure 5.63 Abandonment time prediction for horizontal wells as a function of thickness by this work at A=160 acres, square drainage area, k_h=1 and10md and k_v/k_h=0.1

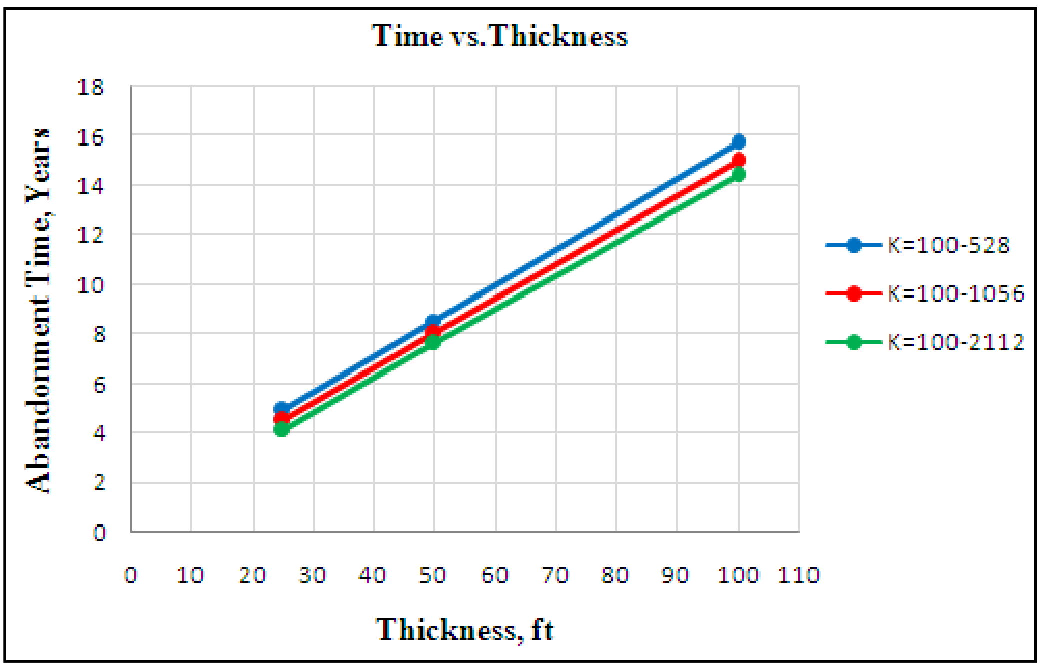

Figure 5.64 Abandonment time prediction for horizontal wells as a function of thickness by this work at A=160 acres, square drainage area, k_h=100md and k_v/k_h=0.1

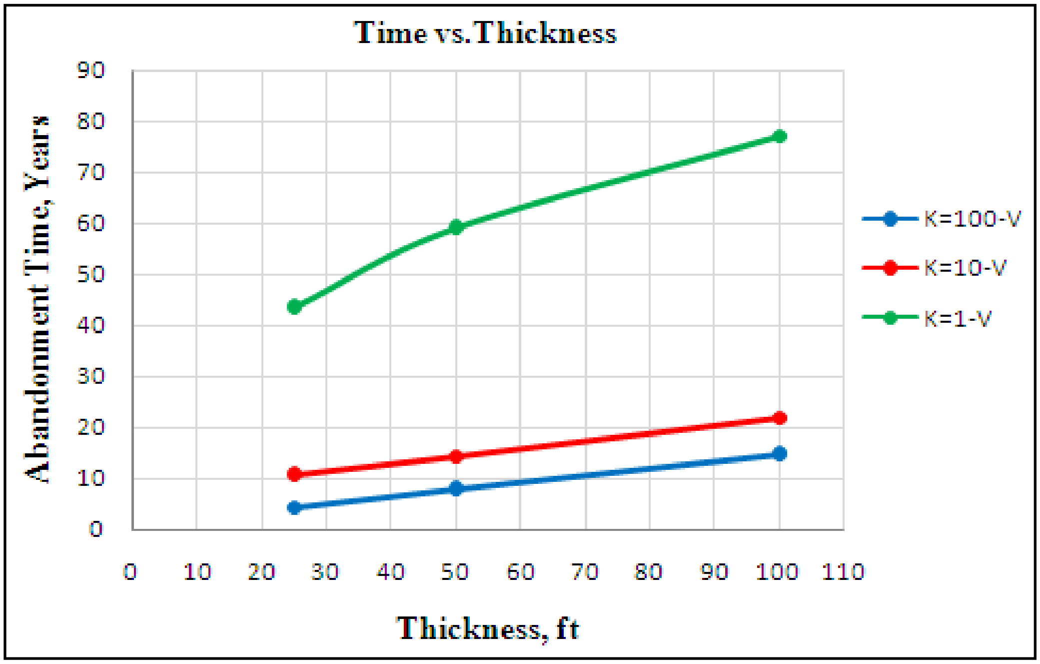

Figure 5.65 Abandonment time prediction for vertical wells as a function of thickness by this work at A=160 acres, square drainage area

Table 5.1 Generalized abandonment time prediction equations for horizontal and vertical wells as a function of thickness for the subject reservoir of this work

R^2	**Equation**	
	$t = -0.001*h^2 + 0.552*h + 14.03$	$L_H = 528$ft, k_h=1md and k_v/k_h=1
1	$t = -3E\text{-}05*h^2 + 0.326*h + 11.76$	$L_H = 1056$ft, k_h =1md and k_v/k_h=1
1	$t = 0.001*h^2 + 0.132*h + 9.5$	$L_H = 2112$ft, k_h =1md and k_v/k_h=1
1	$t = 0.16*h + 2.9$	$L_H = 528$ft, k_h =10md and k_v/k_h=1
1	$t = -5E\text{-}05*h^2 + 0.156*h + 1.633$	$L_H = 1056$ft, k_h =10md and k_v/k_h=1
1	$t= -8E\text{-}05*h^2 + 0.15*h + 0.6$	$L_H = 2112$ft, k_h =10md and k_v/k_h=1
1	$t = -3E\text{-}05*h^2 + 0.14*h + 0.376$	$L_H = 528$ft, k_h =100md and k_v/k_h=1
1	$t = 0.136*h + 0.3$	$L_H = 1056$ft, k_h =100md and k_v/k_h=1
1	$t= -3E\text{-}05*h^2 + 0.138*h + 0.166$	$L_H = 2112$ft, k_h =100md and k_v/k_h=1
1	$t = -0.002*h^2 + 0.792*h + 15.56$	$L_H = 528$ft, k_h =1md and k_v/k_h=0.5
1	$t = -0.001*h^2 + 0.521*h + 12.80$	$L_H = 1056$ft, k_h =1md and k_v/k_h=0.5
1	$t = 0.0001*h^2 + 0.235*h + 10.48$	$L_H = 2112$ft, k_h =1md and k_v/k_h=0.5
1	$t= -5E\text{-}05*h^2 + 0.176*h + 4.033$	$L_H = 528$ft, k_h =10md and k_v/k_h=0.5
1	$t= -3E\text{-}05*h^2 + 0.158*h + 2.566$	$L_H = 1056$ft, k_h =10md and k_v/k_h=0.5
1	$t= -8E\text{-}05*h^2 + 0.154*h + 1.1$	$L_H = 2112$ft, k_h =10md and k_v/k_h=0.5
1	$t= -3E\text{-}05*h^2 + 0.141*h + 0.513$	$L_H = 528$ft, k_h =100md and k_v/k_h=0.5
0.999	$t = 0.135*h + 0.45$	$L_H = 1056$ft, k_h =100md and k_v/k_h=0.5
1	$t = -3E\text{-}05*h^2 + 0.138*h + 0.266$	$L_H = 2112$ft, k_h =100md and k_v/k_h=0.5

Table 5.1- Cont'd

1	$t= -0.004*h^2 + 1.638*h + 15.46$	$L_H = 528ft$, $k_h = 1md$ and $k_v/k_h=0.1$
1	$t = -0.003*h^2 + 1.235*h + 15.56$	$L_H = 1056ft$, $k_h = 1md$ and $k_v/k_h=0.1$
1	$t = -0.002*h^2 + 0.832*h + 13.74$	$L_H = 2112ft$, $k_h = 1md$ and $k_v/k_h=0.1$
1	$t = 0.27*h + 9.166$	$L_H = 528ft$, $k_h = 10md$ and $k_v/k_h=0.1$
1	$t = 0.208*h + 7.1$	$L_H = 1056ft$, $k_h = 10md$ and $k_v/k_h=0.1$
0.999	$t= 0.166*h + 4.9$	$L_H = 2112ft$, $k_h = 10md$ and $k_v/k_h=0.1$
1	$t = -2E-05*h^2 + 0.147*h + 1.245$	$L_H = 528ft$, $k_h = 100md$ and $k_v/k_h=0.1$
1	$t= 0.14*h + 1$	$L_H = 1056ft$, $k_h = 100md$ and $k_v/k_h=0.1$
1	$t = -5E-05*h^2 + 0.144*h + 0.533$	$L_H = 2112ft$, $k_h = 100md$ and $k_v/k_h=0.1$
1	$t= -0.003*h^2 + 0.878*h + 23.61$	For vertical well at $k_h = 1$ md
1	$t= -4E-05*h^2 + 0.156*h + 6.650$	For vertical well at $k_h = 10$ md
1	$t = -3E-05*h^2 + 0.138*h + 0.938$	For vertical well at $k_h = 100$ md

5.8 Selection of Well Type Based on Reservoir Properties

For each set of well and reservoir parameters considered in this reservoir simulation study, Table A.23 shows the ratio of oil and gas recovery factors for the horizontal well to the oil and gas recovery factors for the vertical well. This table also shows the ratio of the time to reach abandonment condition for the vertical well to the time to reach abandonment condition for each case. For the first time in the petroleum engineering literatare, this research is introducing the concept that consideration of these four ratios will enable the petroleum engineer to properly determine the best well type in a given retrograde gas-condensate reservoir. For each reservoir, the last column of Table A.23 shows the well type chosen with the use of these four ratios.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Based on the analysis of the results obtained in this research study, the following conclusions can be made with regards to the effects of well and reservoir parameters on the performance of horizontal and vertical wells in retrograde gas-condensate reservoirs:

1. For vertical wells, the lowest oil recovery factor (24.4%) corresponds to thick reservoirs (h=100 feet) with low horizontal permeability (k_h = 1 md), regardless of drainage area size. This is due to the high pressure drop created in a larger pore volume around a vertical well located in thick reservoirs with low hoirzontal permeability, resulting in oil dropping out of gas in these areas and left in the reservoir at abandonment. The gross-gas and free-gas recovery factors for this reservoir are 77.2% and 81.9%, respectively.
2. For vertical wells, the reservoir associated with the lowest oil recovery factor is not the reservoir with lowest recovery factors for gross-gas and free-gas. The lowest recovery factor for gross-gas (70.3%) and free-gas (74.1%) correspond to a thin reservoir (h = 25 feet) with low horizontal permeability (k_h = 1 md). This is also due to the high pressure drop created around a vertical well located in a thin reservoir with low horizontal permeability.

3. For vertical wells, the highest oil recovery factor (29.2%) corresponds to thin reservoir (h = 25 feet) with high horizontal permeability (k_h = 100 md), regardless of the drainage area size. Interestingly, this does correspond to the highest recovery factor for both gross-gas and free-gas.
4. For horizontal wells, unlike the case for the vertical wells, the lowest oil recovery factor (12%) corresponds to thin reservoirs (h = 25 feet) with low horizontal permeability (k_h = 1 md), k_v/k_h value of 0.1, and horizontal well penetration ratio of 0.8, regardless of drainage area size. The gross-gas and free-gas recovery factors for this reservoir are 70.5% and 75.6%, respectively.
5. For horizontal wells, as was the case for vertical wells, the reservoir associated with the lowest oil recovery factor is not the reservoir with lowest recovery factors for gross-gas and free-gas. The lowest recovery factor for gross-gas (61.2%) and free-gas (64.8%) correspond to a thin reservoir (h = 25 feet) with low horizontal permeability (k_h = 1 md), k_v/k_h value of 0.1, and horizontal well penetration ratio of 0.2.
6. For horizontal wells, the highest oil recovery factor (29.5%) corresponds to thin reservoir (h = 25 feet) with high horizontal permeability (k_h = 100 md) and k_v/k_h values of 0.5 and higher, for all values of the horizontal well penetration ratio and drainage area sizes considered. Interestingly, this reservoir does correspond to the highest recovery factor for both gross-gas (81.7%) and free-gas (86.2%). It is important to note that, the same reservoir with k_v/k_h value of 0.1 also had recovery factors for oil, gross-gas, and free-gas almost near these highest recovery factors. One may be able to conclude that thin retrograde gas-condensate reservoir with high horizontal permeability (k_h = 100 md) and k_v/k_h values greater than about 0.2 will

yield the highest recovery factors for oil, gross-gas and free-gas, for values of the horizontal well penetration ratio greater than 0.2.

7. The ratio of time to reach abandonment conditions for the vertical well to the time to reach abandonment conditions for the horizontal well in the same reservoir, along with the ratios of the recovery factors for the gross-gas, free-gas, and oil of the two wells, as well as the actual time to reach the abandonment condition for the horizontal well are used in order to select the well type that will have a better performance in each reservoir case considered.
8. Reservoirs with high horizontal permeability (such as k_h = 100 md) should be developed with vertical wells, for all values of k_v/k_h and horizontal well penetration ratios considered.
9. Reservoirs with intermediate horizontal permeability (such as k_h = 10 md) should be developed with horizontal wells of penetration ratio greater than 0.4, when k_v/k_h value is 0.5 and higher, for all values of formation thicknesses considered.
10. Reservoirs with low horizontal permeability (such as k_h = 1 md) should be developed with horizontal wells, for values of k_v/k_h values of 0.5 and higher and all values of horizontal well penetration ratios considered.
11. For the vertical well, the lower the values of horizontal permeability and formation thickness, the higher the average reservoir pressure at abandonment time.
12. For the horizontal well, the lower the values of formation permeability, formation thickness, k_v/k_h ratio, and horizontal well penetration ratio, the higher the average reservoir pressure at abandonment time.

13. The lower the values of horizontal permeability and formation thickness, and the higher the value of k_v/k_h and horizontal well penetration ratio, the better the performance of horizontal well over the performance of vertical well.
14. Simple algebraic equations presented in Table 5.1 can be used to calculate the abandonment time as a function of well and reservoir parameters.
15. Tables A.21, A.22, and A.23 can be used by reservoir engineers to select the appropriate well type in a given reservoir, to determine the recovery factors for gross-gas, free-gas and oil, and to determine the abandonment pressure and abandonment time.

6.2 Recommendations

Due to the low recovery factor for oil, this research recommends further study in order to investigate the effect of maintenance of reservoir pressure at or near the dew-point pressure on oil recovery factor, for each reservoir case considered in this research study. Pressure maintenance by injection of produced free-gas and by injection of carbon dioxide (with the additional goal of underground sequestration) should be investigated.

NOMENCLATURE

A	Drainage area, acres
API	American Petroleum Institute
BHP	Bottom hole pressure, psia
B_g	Gas formation volume factor, RCF/SCF
B_o	Oil formation volume factor, RB/STB
B_w	Water formation volume factor, Res/STD
CCE	Constant composition expansion
C_f	Rock Compressibility, 1/psi
CVD	Constant-volume depletion
Cw	Water compressibility, 1/psi
DWs	Deviated wells
FG_H	Free gas recovery factor for horizontal well, %
FG_V	Free gas recovery factor for vertical well, %
FGRF	Free gas recovery factor, %
GG_H	Gross gas recovery factor for horizontal well, %

GG_V	gross gas recovery factor for vertical well, %
GGRF	Gross gas recovery factor, %
FGIP	Initial gas in place, MSCF
FOIP	Initial oil in place, STB
FGPR	Gas production rate, MSCF/D
FOPR	Oil production rate, STB/D
GOR	Gas oil ratio, SCF/STB
h	Reservoir thickness, ft
H	Horizontal well
IPR	Inflow performance relations MSCF/D/Psi
K_h	Horizontal permeability, md
K_v	Vertical permeability, md
K_{rg}	Gas relative permeability
K_{ro}	Oil relative permeability
$L_{\mathbf{H}}$	Length for a horizontal well, ft
$L_{\mathbf{H}}/2X_e$	Horizontal well penetration
NX	Number of grids in X-direction
NY	Number of grids in Y-direction
NZ	Number of grids in Z-direction

OR_H	Oil recovery factor for horizontal well, %
OR_V	Oil recovery factor for vertical well, %
ORF	Oil recovery factor, %
P_c	Critical Pressures, psia
P_d	Dew-point pressure, psia
P_i	Initial reservoir pressure, psia
PR	Productivity ratio
PRP	Average reservoir pressure, psia
R	Rectangular drainage area shape
r_{wh}	Horizontal well radius, ft
r_{wv}	Vertical well radius, ft
S	Square drainage area shape
Sg	Initial gas saturation, %
S_o	Initial oil saturation, %
S_w	Initial water saturation, %
T	Initial reservoir temperature, °F
T_c	Critical Temperatures, °F
t_H	Abandonment time for a horizontal, Years

t_V Abandonment time for a vertical, Years

V Vertical wells

V_c Critical Volumes, ft^3/lb-mol

$2X_e$ X-direction resevvoir dimensions, ft

Zc Critical Z-Factors

Greek Symbols:

ρ_g Gas density, lbs/ft^3

ρ_o Oil density, lbs/ft^3

ρ_w Water density, lbs/ft^3

μ_w Water viscosity, cp

Ø Reservoir porosity,%

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APPENDIX

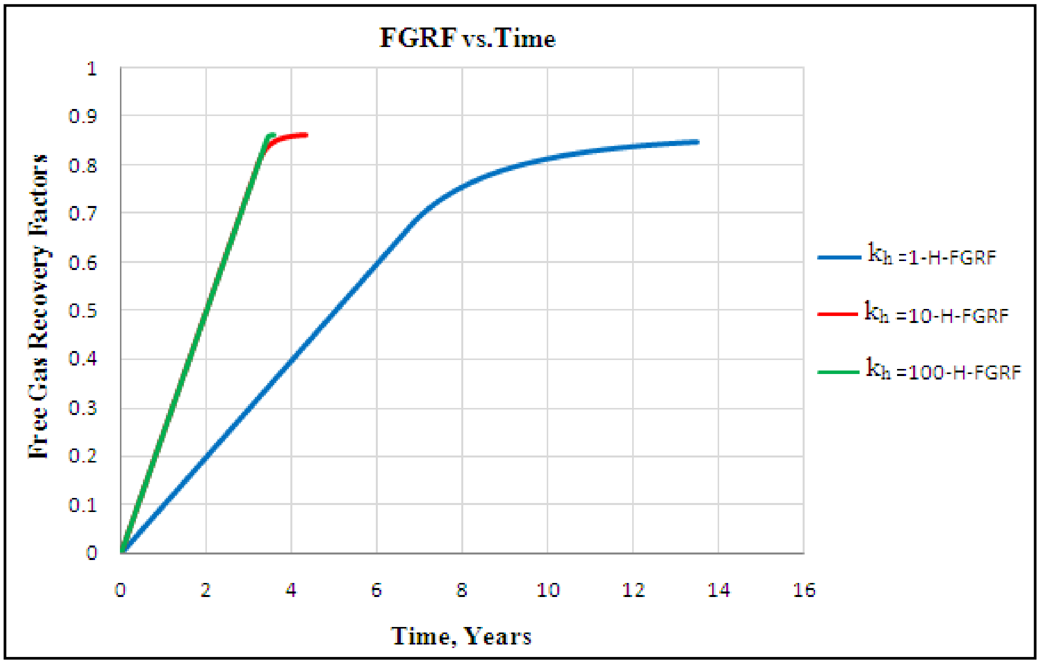

Figure A.1 Effect of k_h on free gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, L_H =2112ft and k_v/k_h=1

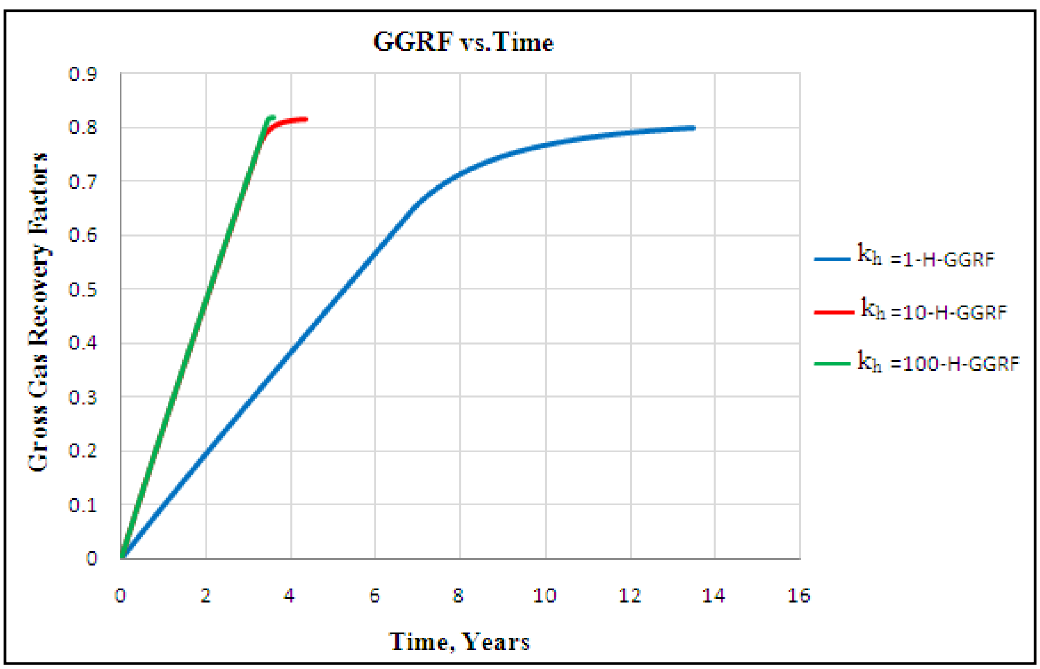

Figure A.2 Effect of k_h on gross gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, L_H =2112ft and k_v/k_h=1

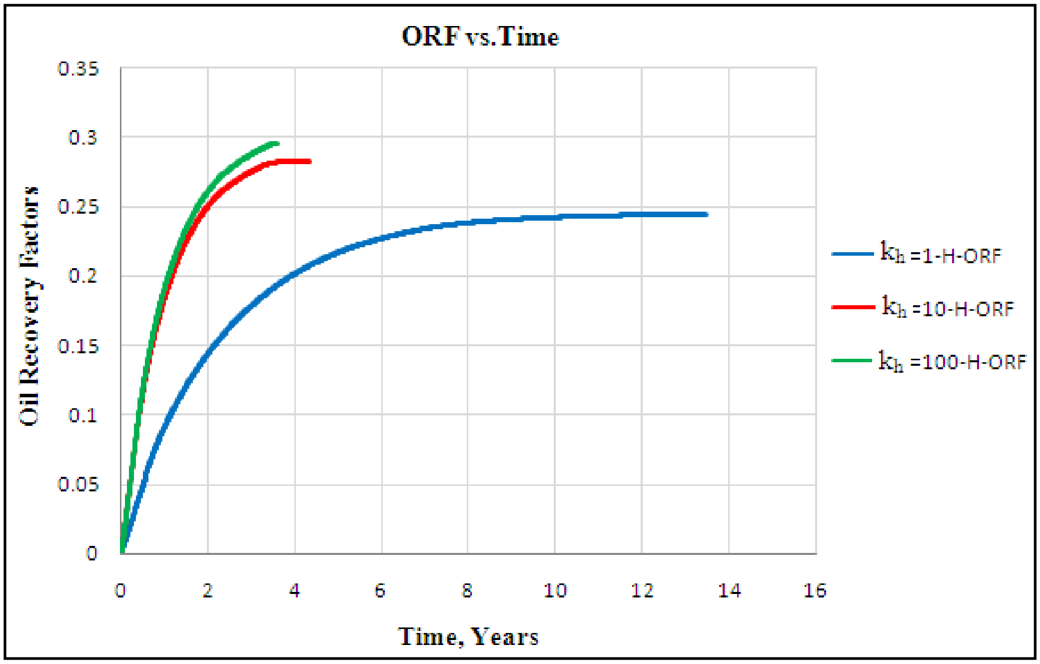

Figure A.3 Effect of k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, L_H=2112ft and k_v/k_h=1

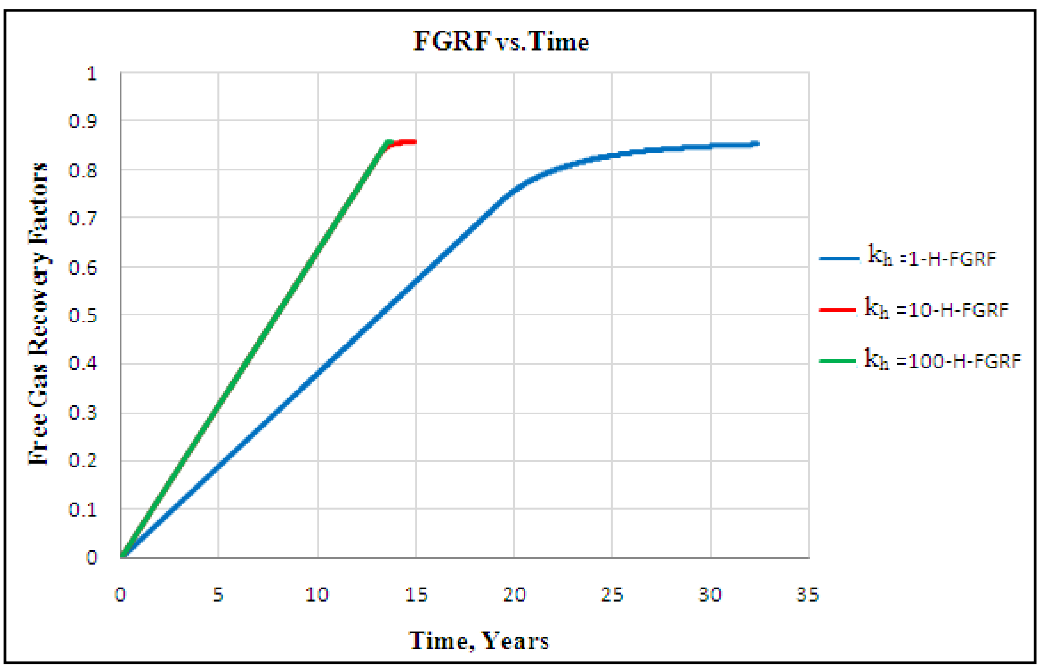

Figure A.4 Effect of k_h on free gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=100ft, L_H =2112ft and k_v/k_h=1

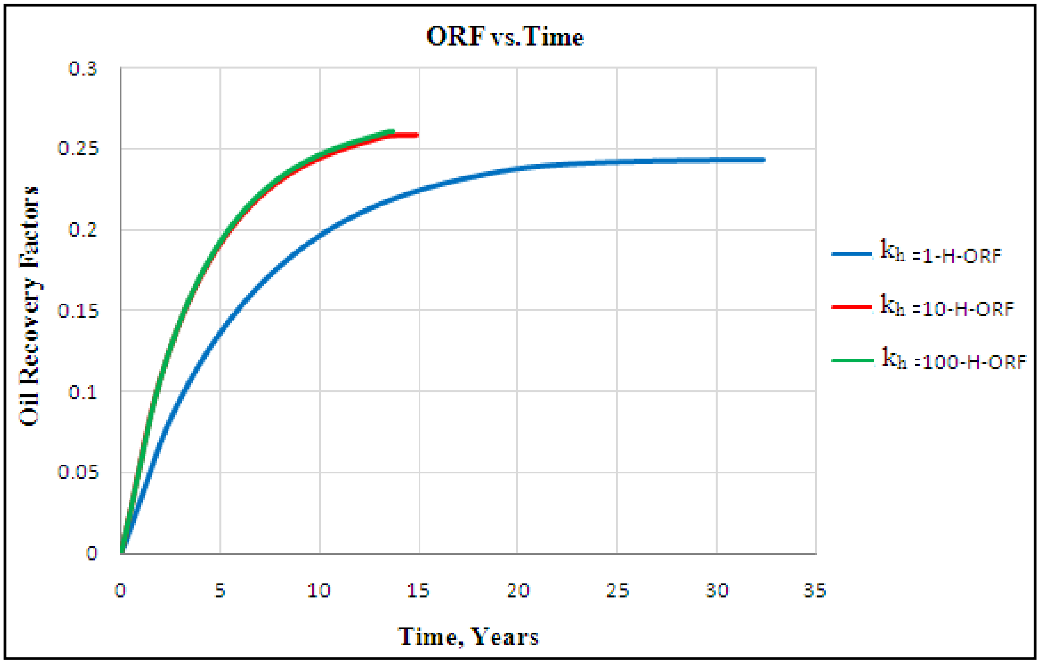

Figure A.5 Effect of k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=100ft, L_H=2112ft and k_v/k_h=1

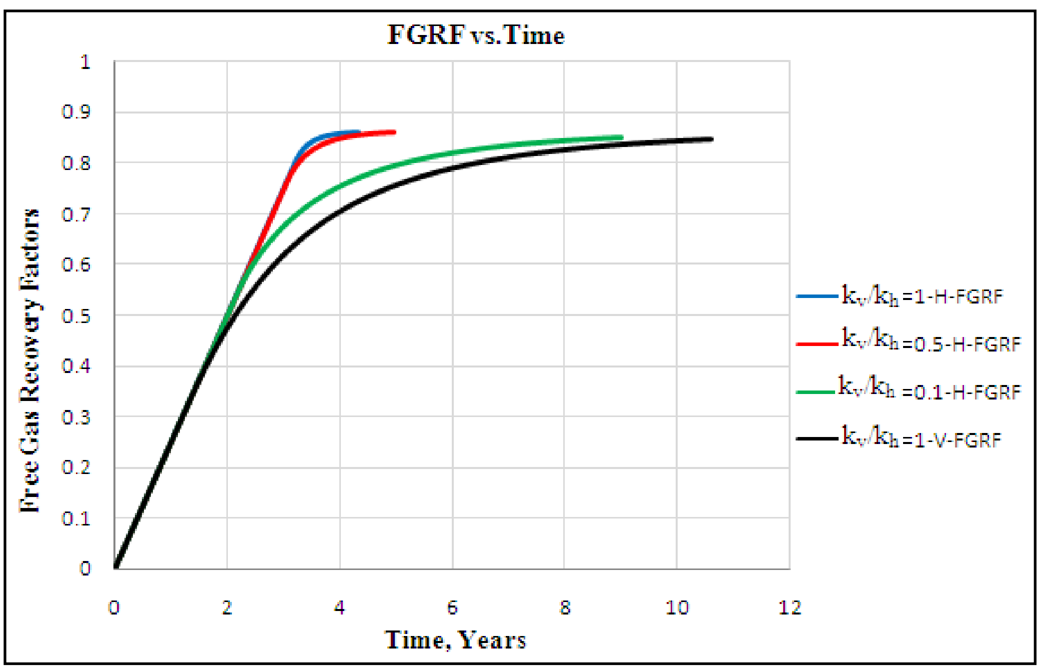

Figure A.6 Effect of k_v/k_h on free gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=10md and L_H =2112ft

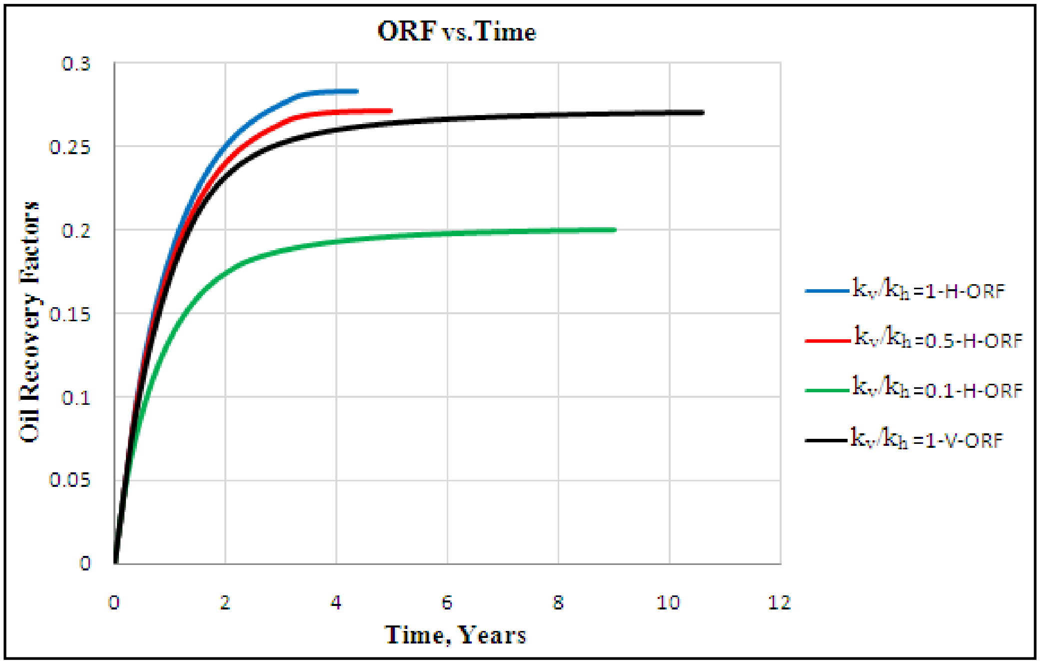

Figure A.7 Effect of k_v/k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=10md and L_H=2112ft

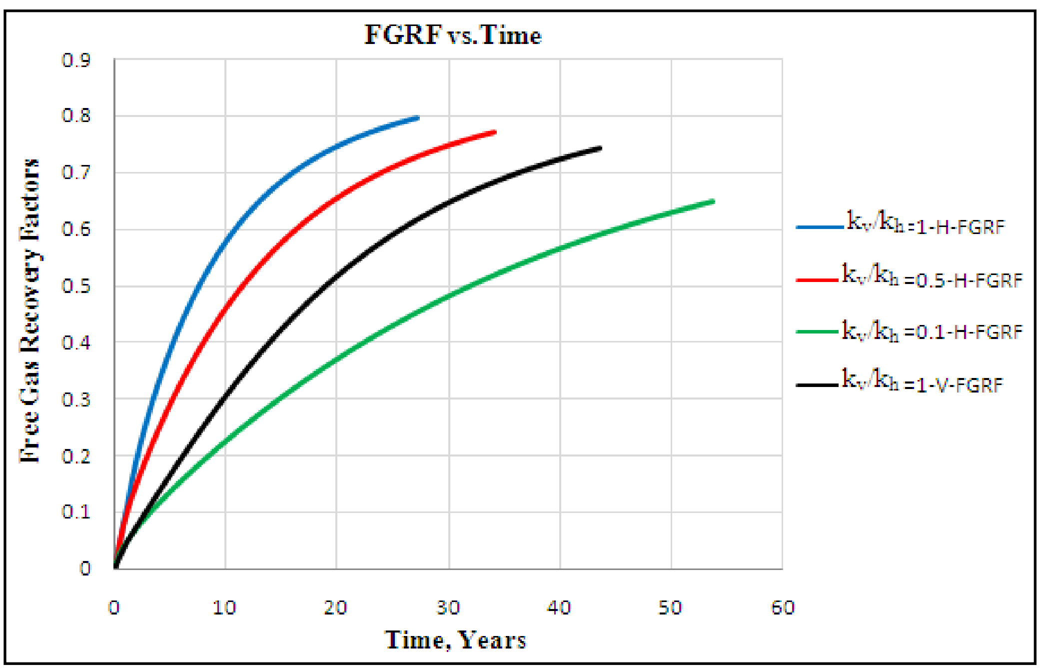

Figure A.8 Effect of k_v/k_h on free gas recovery factors for horizontal wells at A= 160 acres, square drainage area, h=25ft, k_h=1md and L_H=528ft

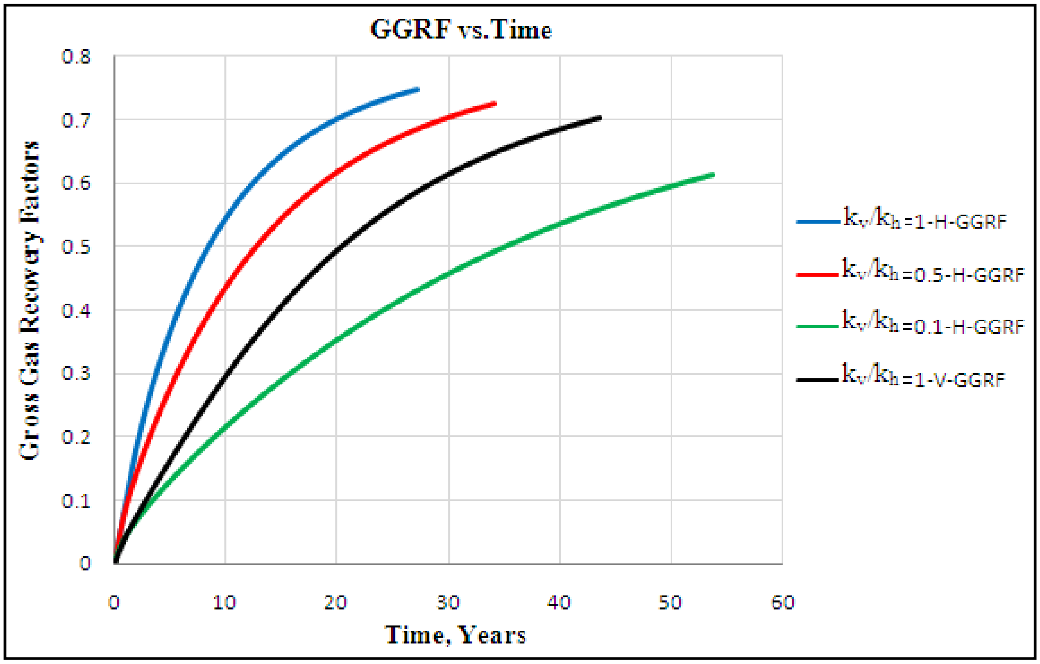

Figure A.9 Effect of k_v/k_h on gross gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=1 md and L_H =528ft

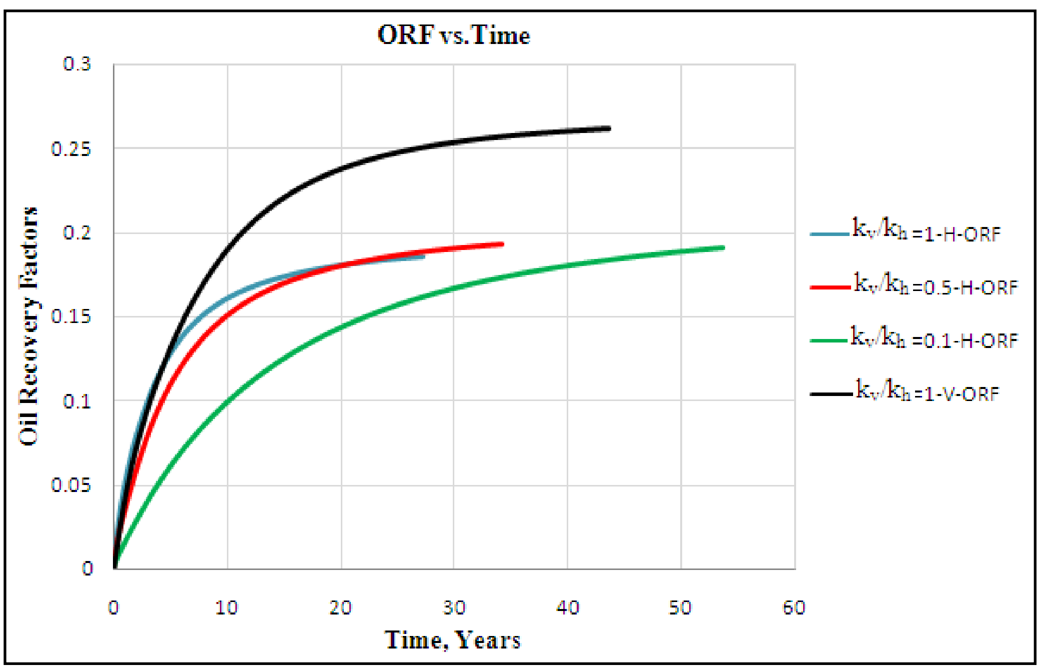

Figure A.10 Effect of k_v/k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=1md and L_H =528ft

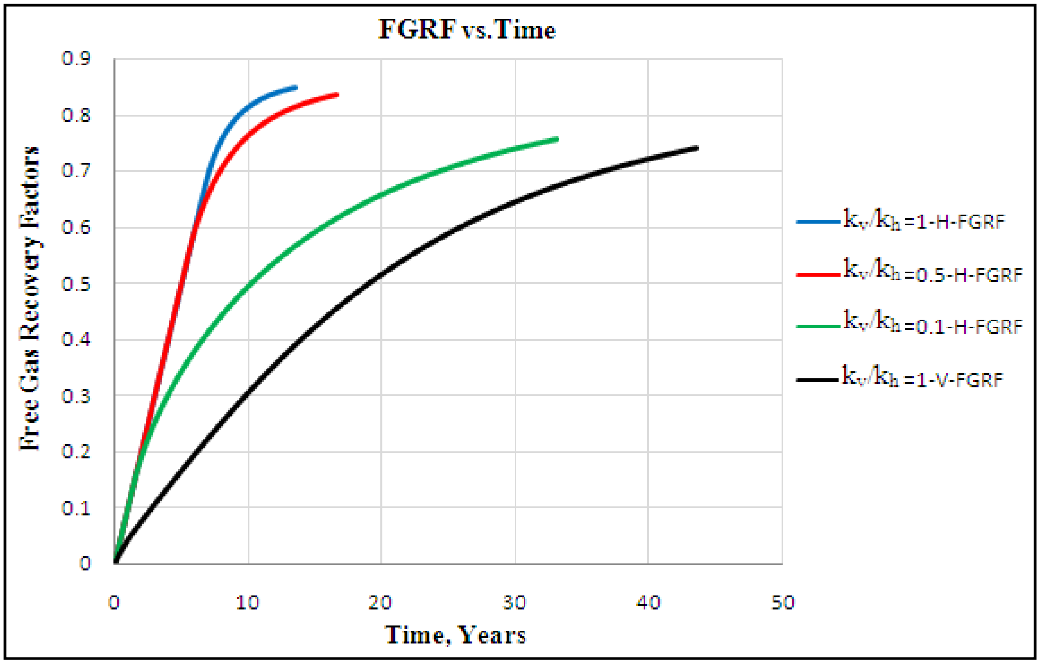

Figure A.11 Effect of k_v/k_h on free gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=1md and L_H=2112ft

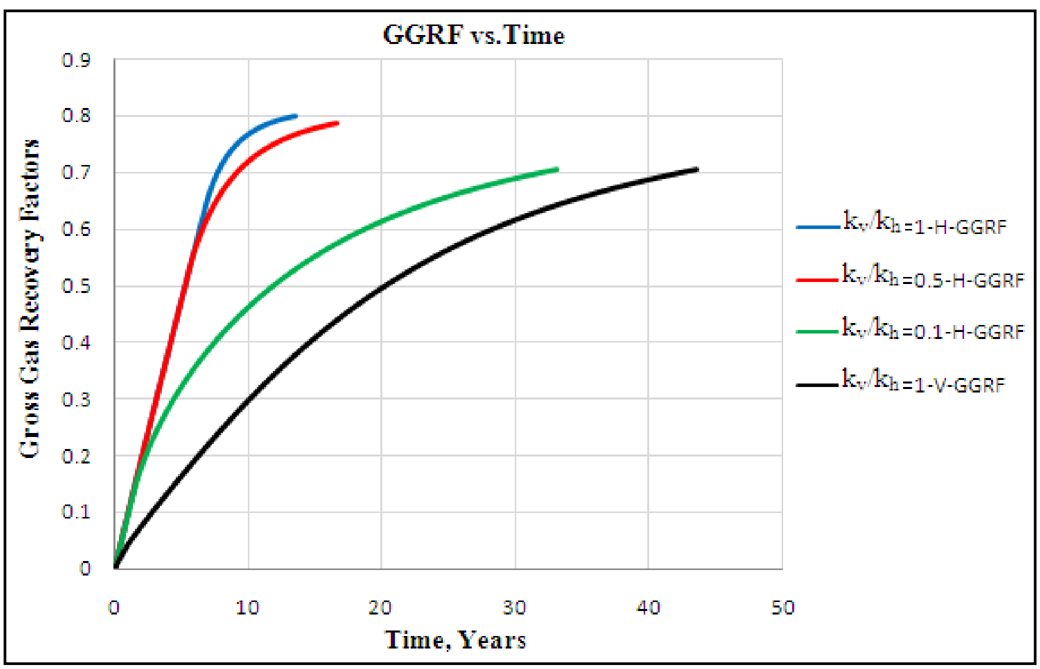

Figure A.12 Effect of k_v/k_h on gross gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=1md and L_H =2112ft

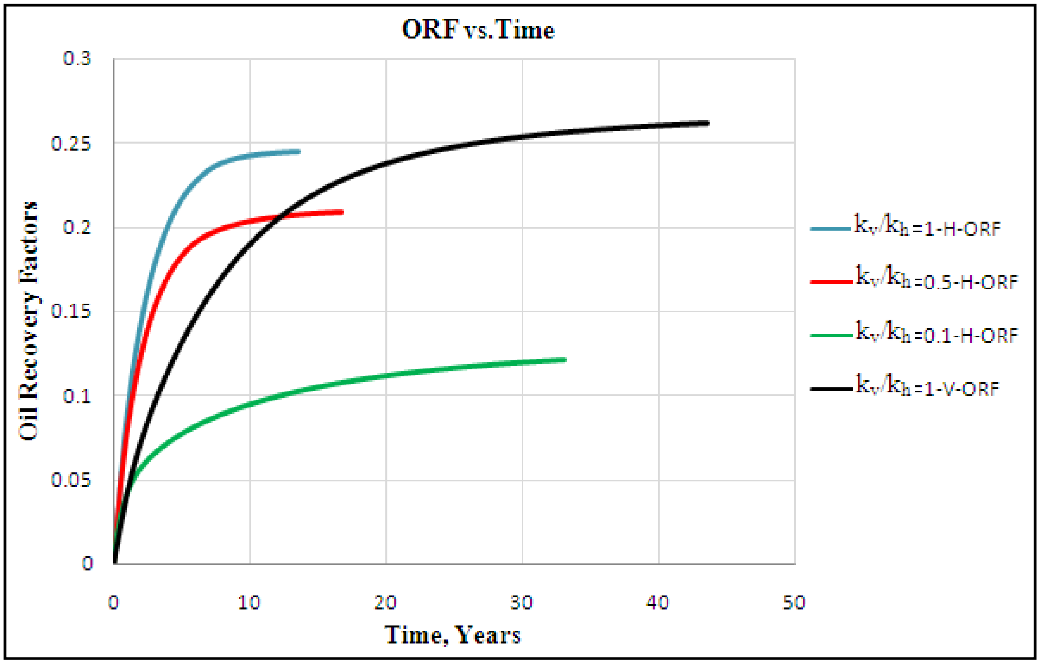

Figure A.13 Effect of k_v/k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=1md and L_H=2112ft

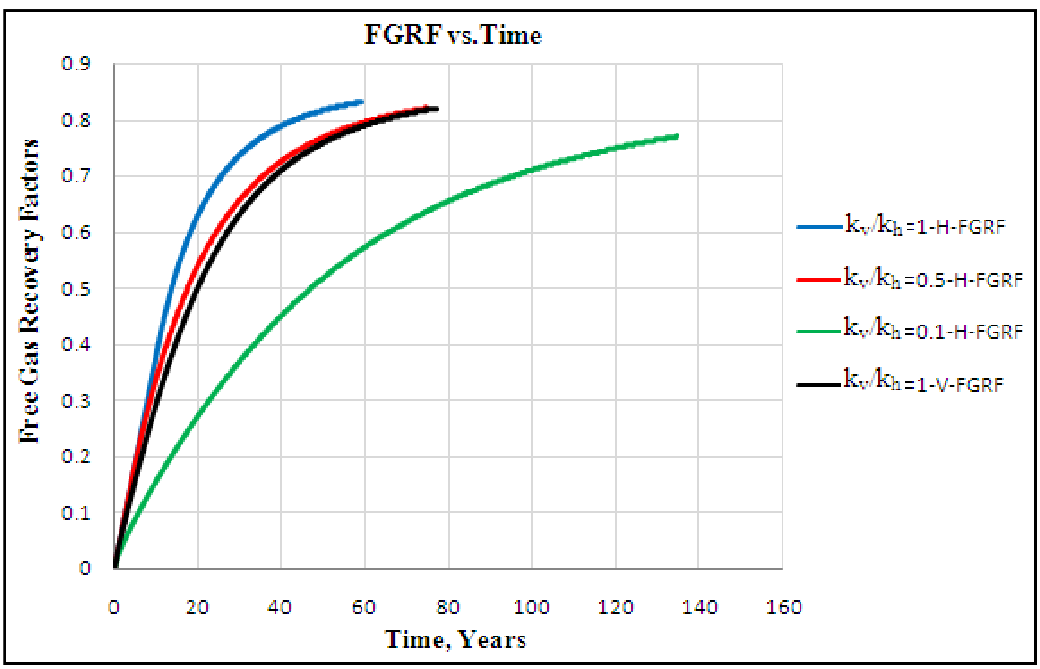

Figure A.14 Effect of k_v/k_h on free gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=1md and L_H =528ft

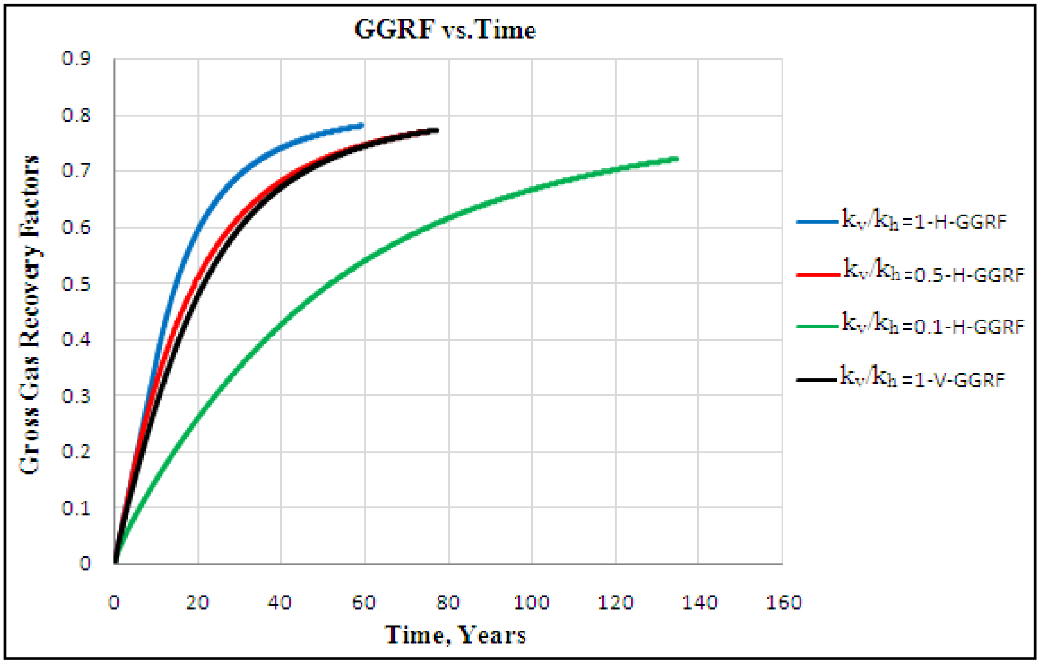

Figure A.15 Effect of k_v/k_h on gross gas recovery factors for horizontal wells at A= 160 acres, square drainage area, h=100ft, k_h=1md and L_H=528ft

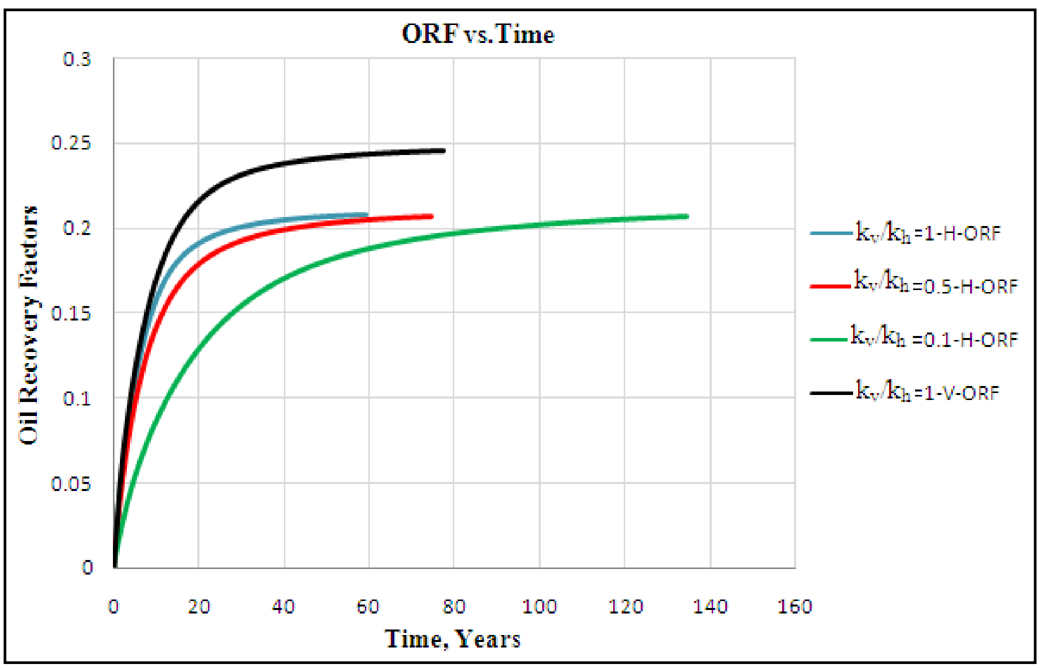

Figure A.16 Effect of k_v/k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=1md and L_H =528ft

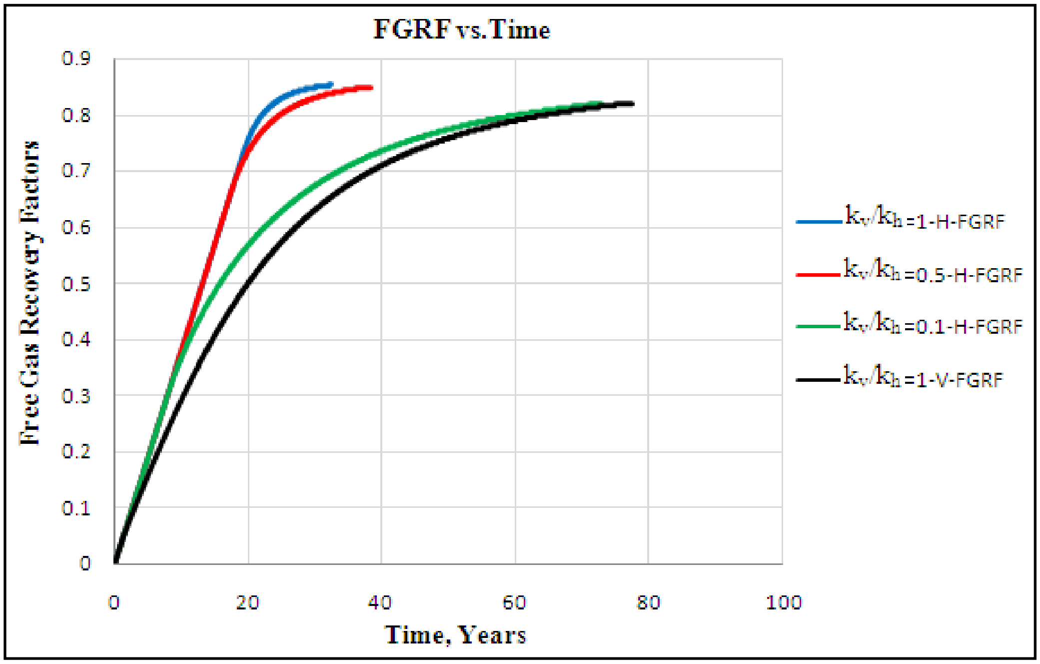

Figure A.17 Effect of k_v/k_h on free gas recovery factors for horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=1md and L_H=2112ft

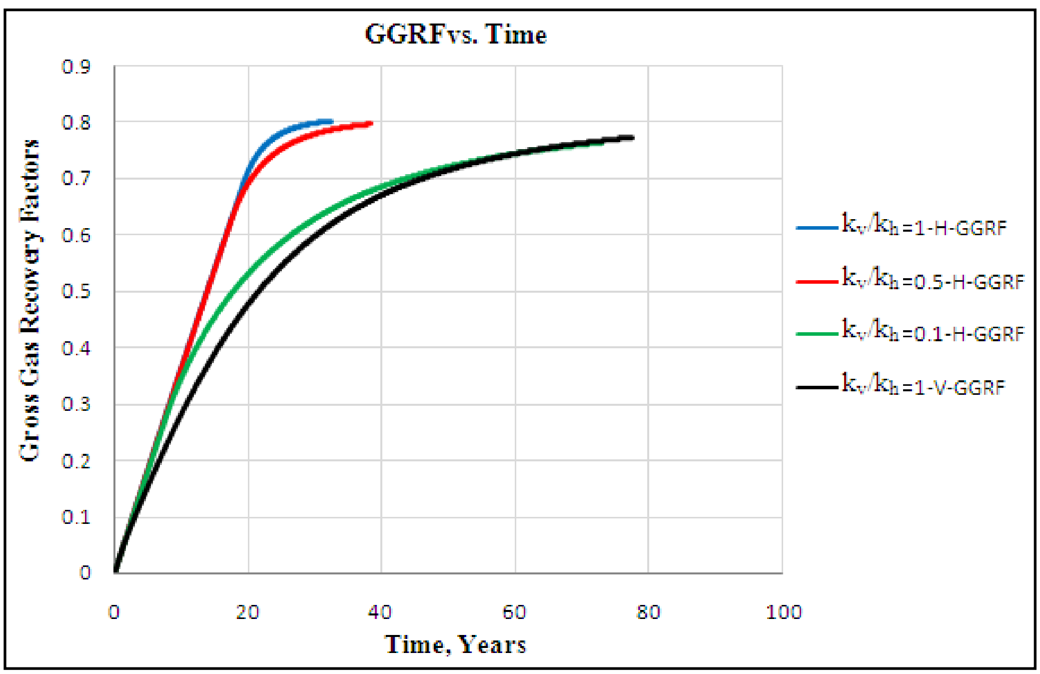

Figure A.18 Effect of k_v/k_h on gross gas recovery factors for horizontal wells at A= 160 acres, square drainage area, h=100ft, k_h=1md and L_H=2112ft

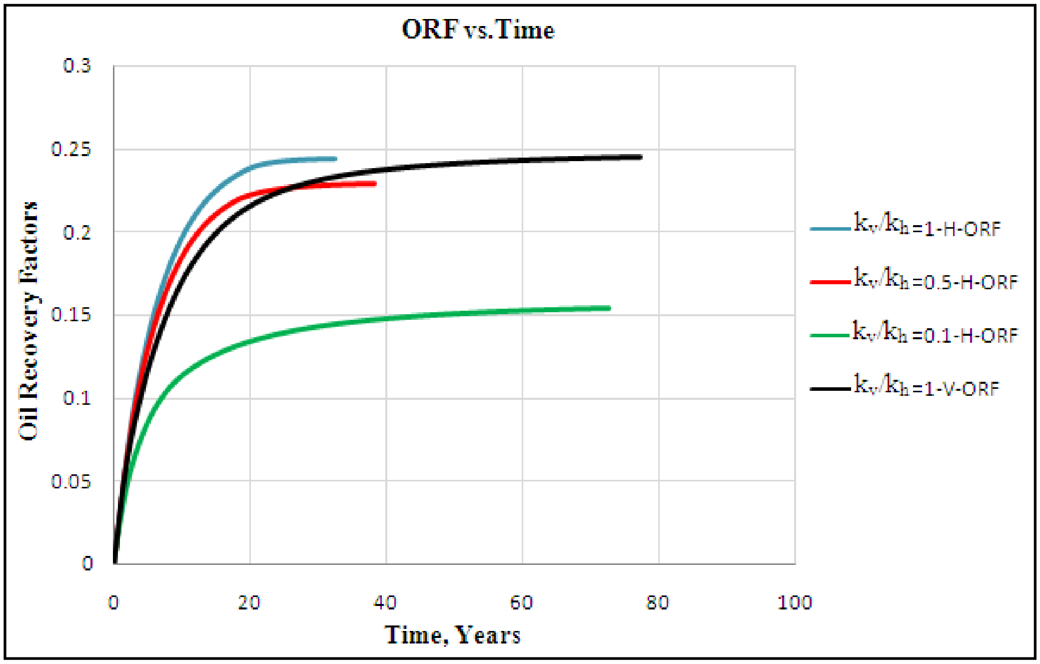

Figure A.19 Effect of k_v/k_h on oil recovery factors for horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=1md and L_H =2112ft

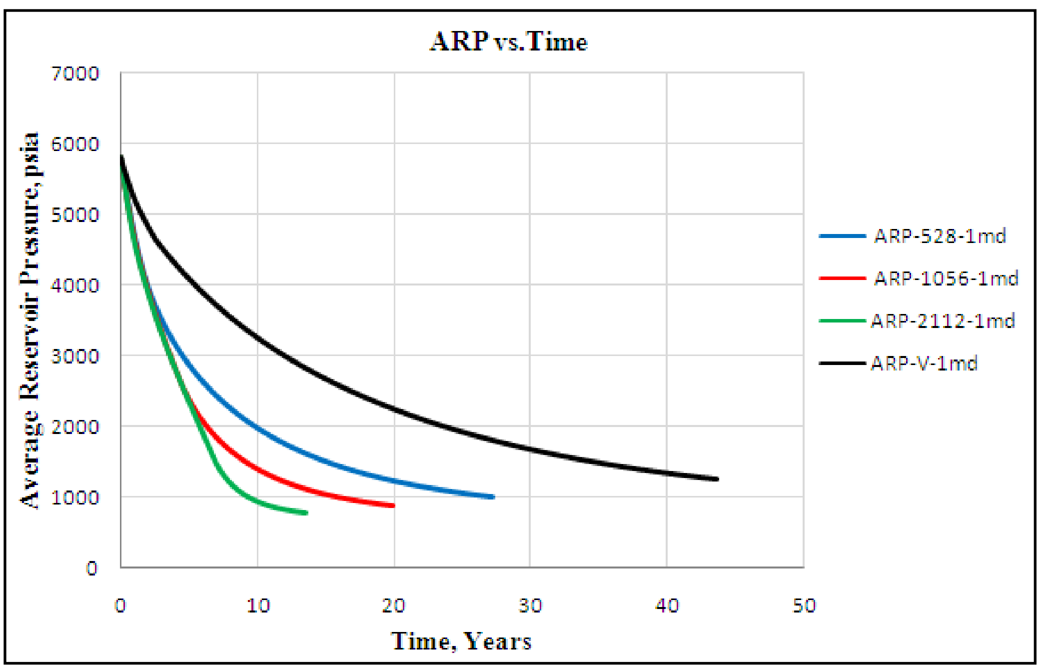

Figure A.20 Average reservoir pressure for vertical and horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=1md and k_v/k_h=1

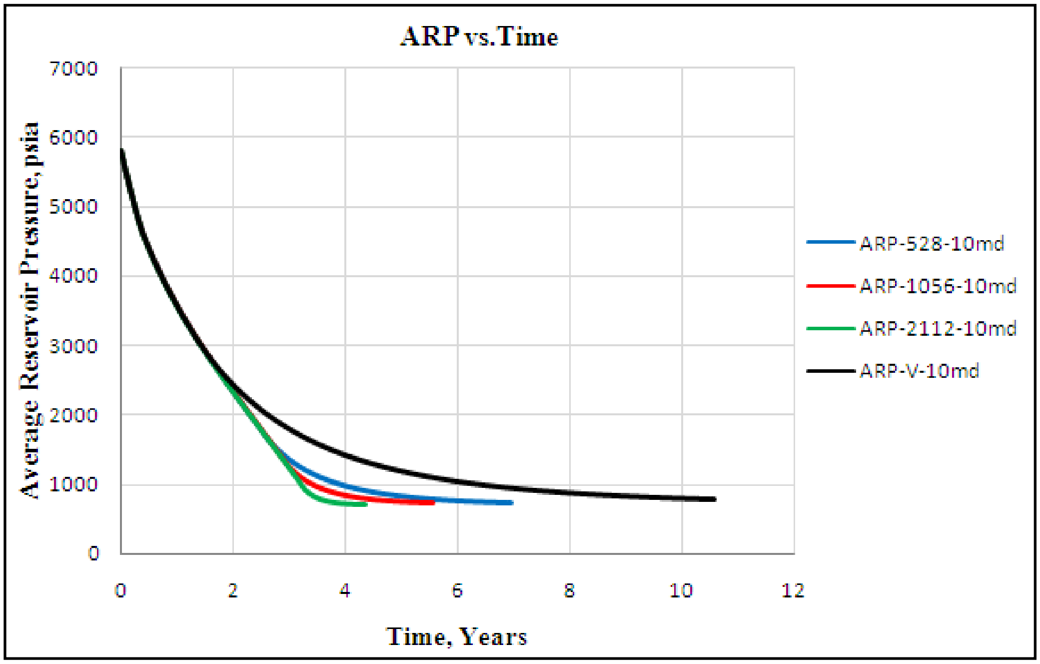

Figure A.21 Average reservoir pressure for vertical and horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=10md and k_v/k_h=1

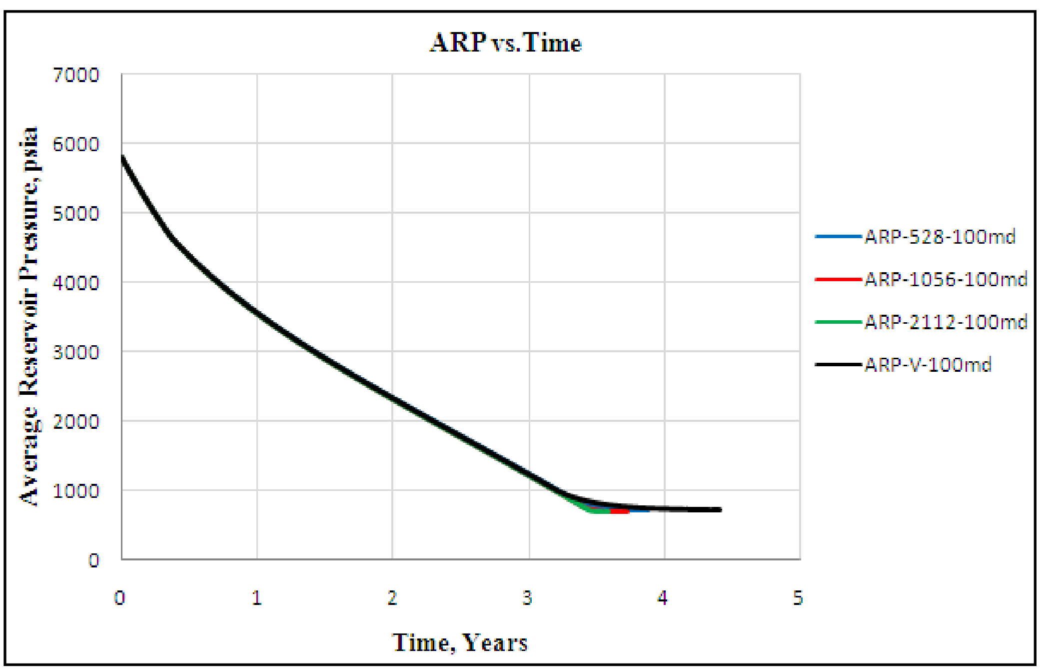

Figure A.22 Average reservoir pressure for vertical and horizontal wells at A=160 acres, square drainage area, h=25ft, k_h=100md and k_v/k_h=1

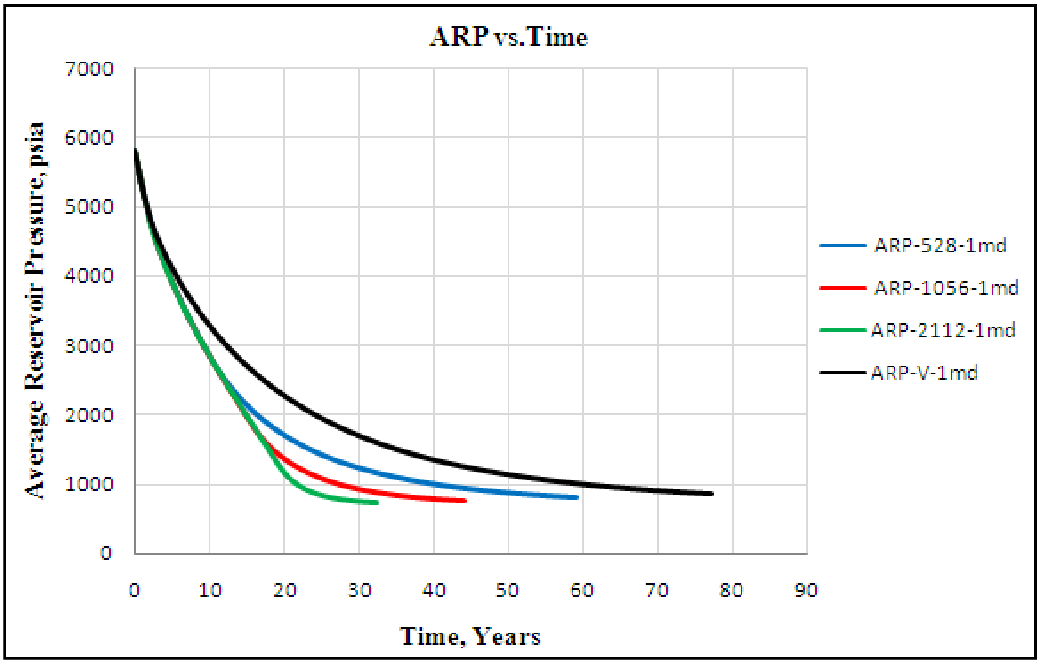

Figure A.23 Average reservoir pressure for vertical and horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=1md and k_v/k_h=1

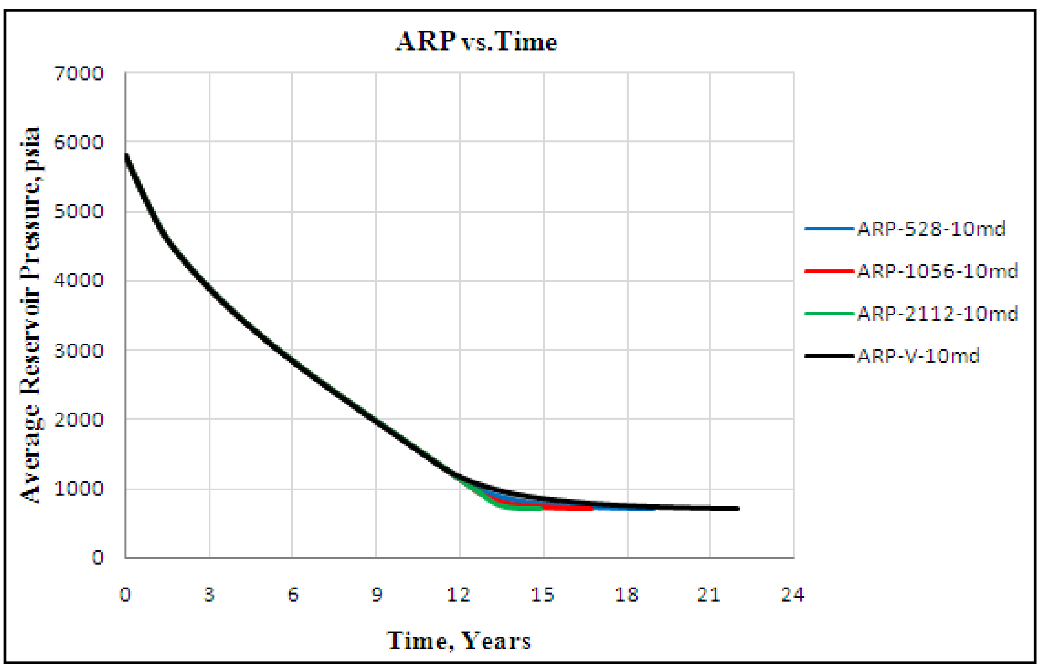

Figure A.24 Average reservoir pressure for vertical and horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=10md and k_v/k_h=1

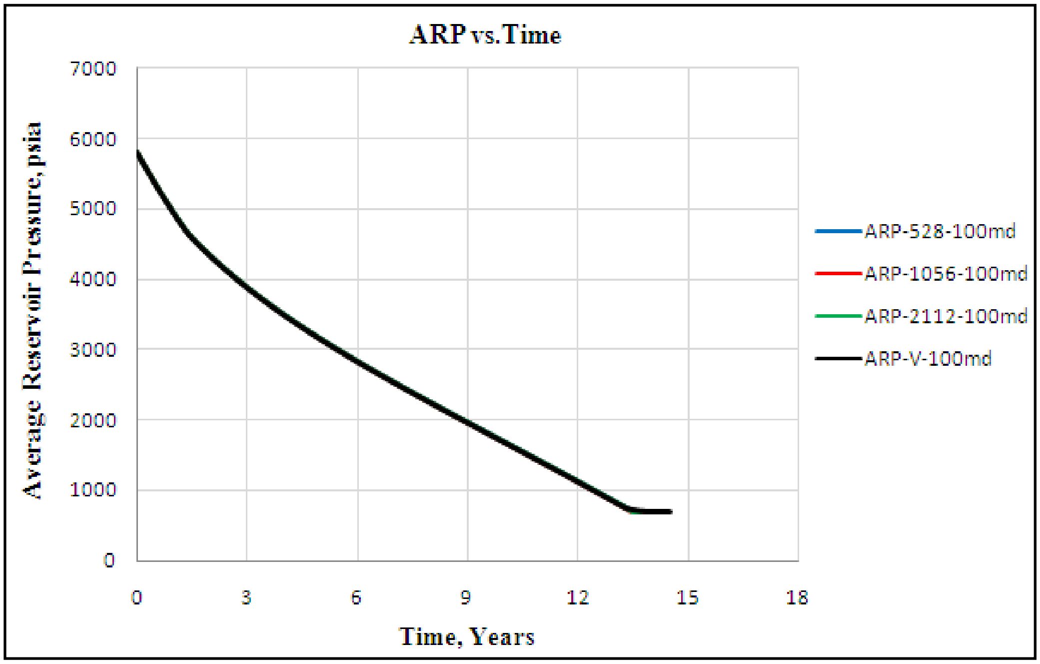

Figure A.25 Average reservoir pressure for vertical and horizontal wells at A=160 acres, square drainage area, h=100ft, k_h=100md and k_v/k_h=1

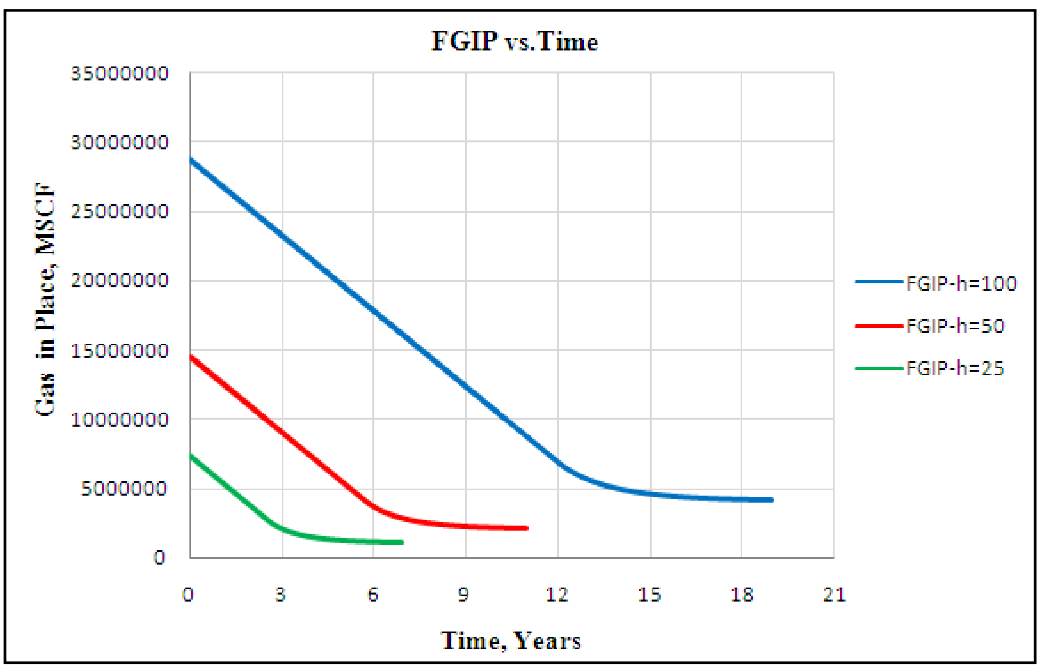

Figure A.26 Gas in place at A=160 acres, square drainage area, k_h=10md and L_H =528ft

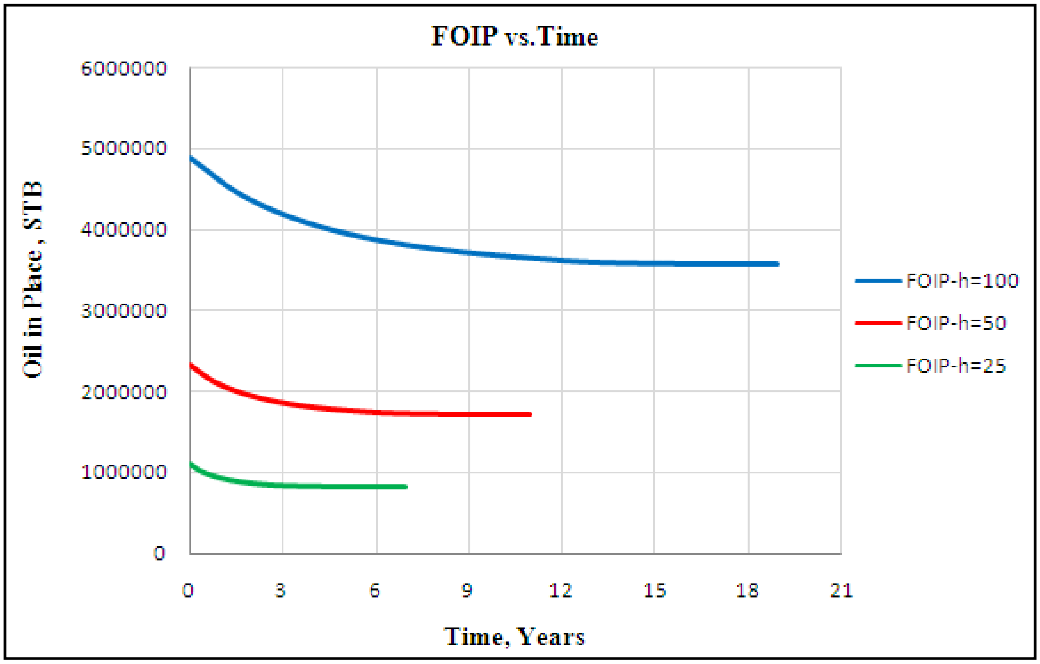

Figure A.27 Oil in place at A=160 acres, square drainage area, k_h=10md and L_H =528ft

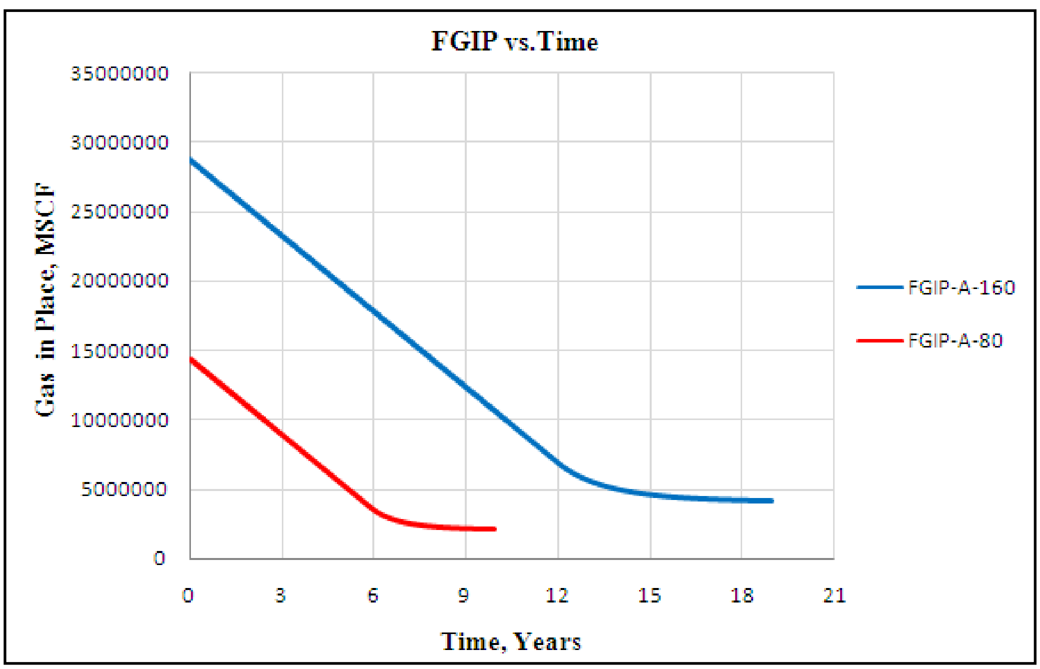

Figure A.28 Gas in place at A=160 and 80 acres, square drainage areas, h=100ft and k_h =10md

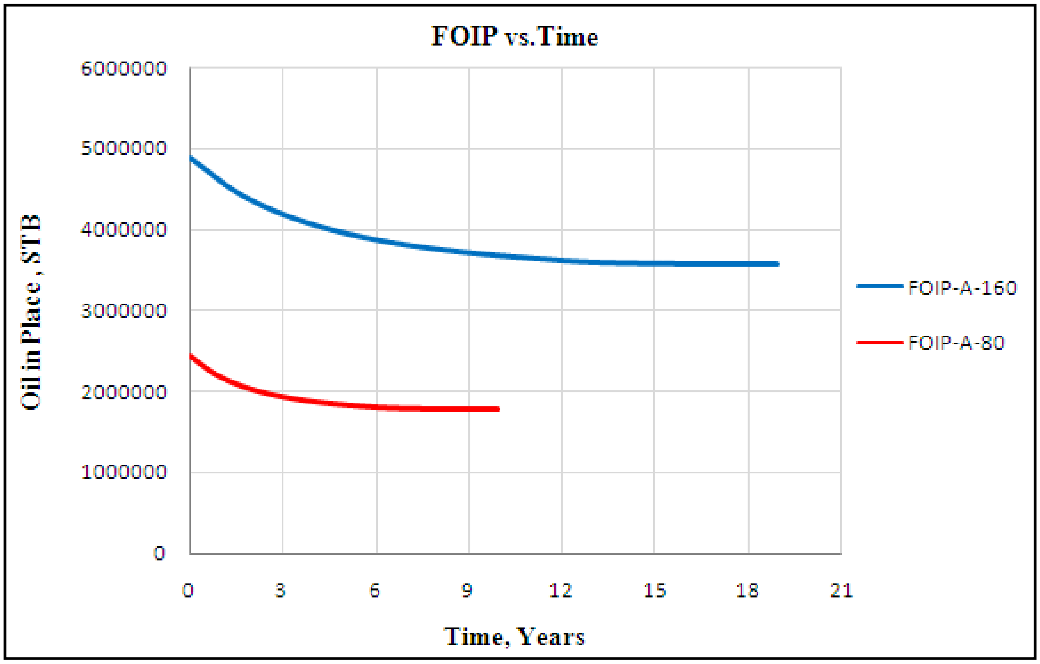

Figure A.29 Oil in place at A=160 and 80 acres, square drainage areas, h=100ft and k_h =10md

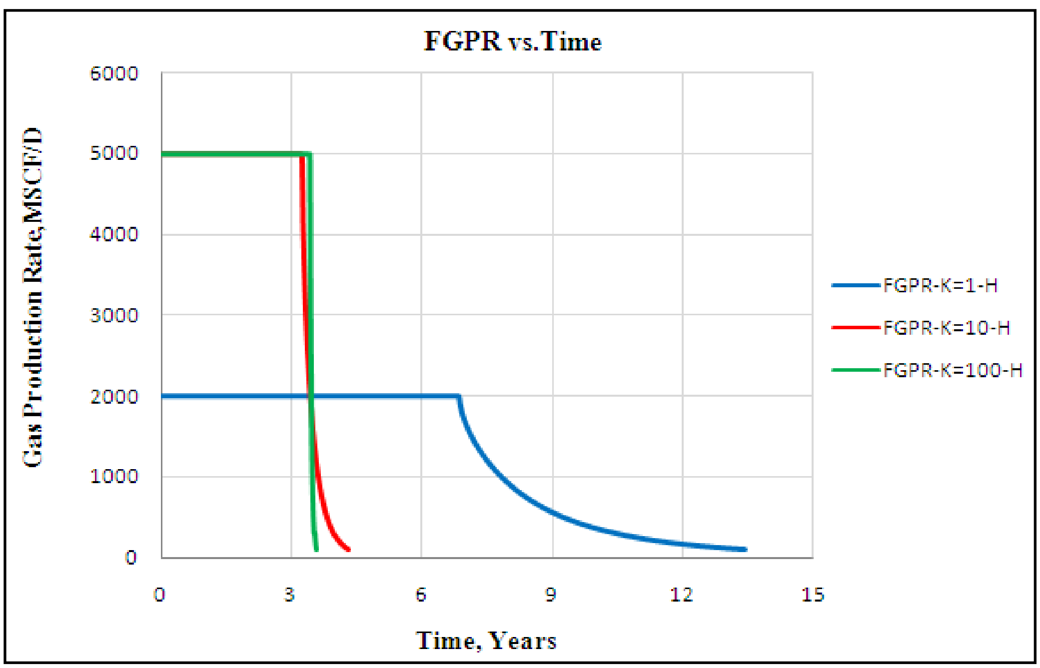

Figure A.30 Gas production rate for horizontal wells at A=160 acres, square drainage area, h=25ft and L_H=2112ft

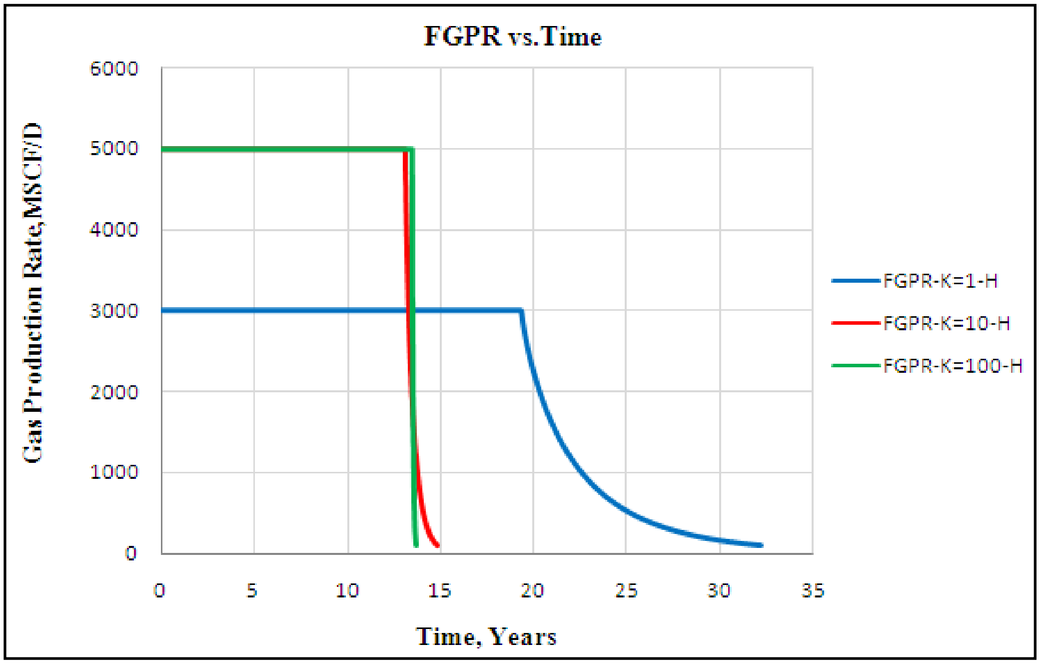

Figure A.31 Gas production rate for horizontal wells at A=160 acres, square drainage area, h=100ft and L_H=2112ft

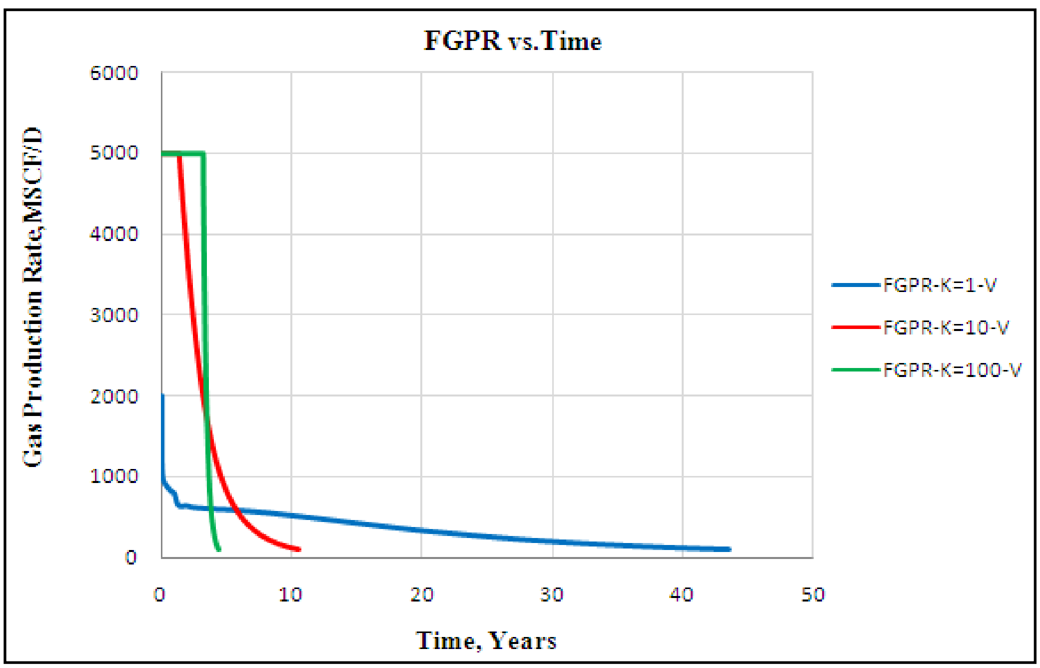

Figure A.32 Gas production rate for vertical wells at A=160 acres, square drainage area and h=25ft

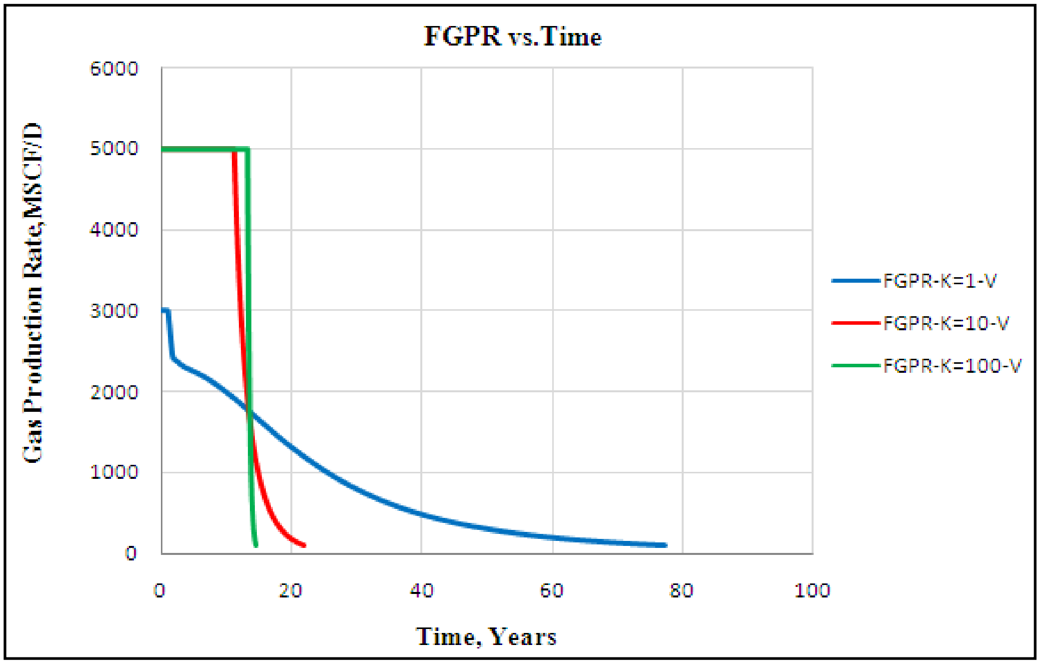

Figure A.33 Gas production rate for vertical wells at A=160 acres, square drainage area and h=100ft

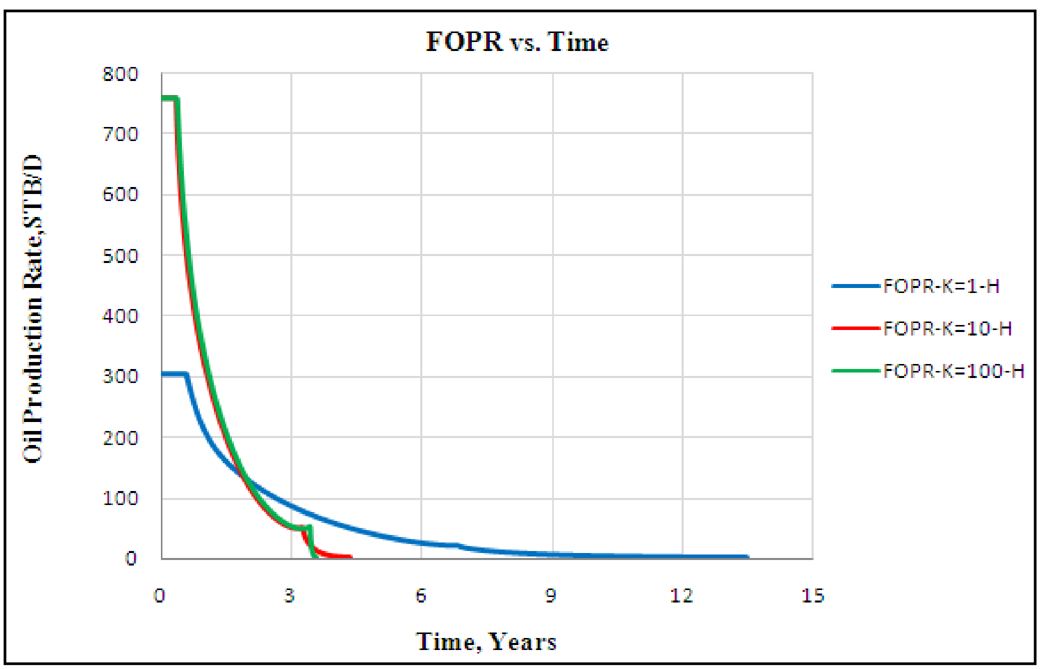

Figure A.34 Oil production rate for horizontal wells at A=160 acres, square drainage area, h=25ft and L_H=2112ft

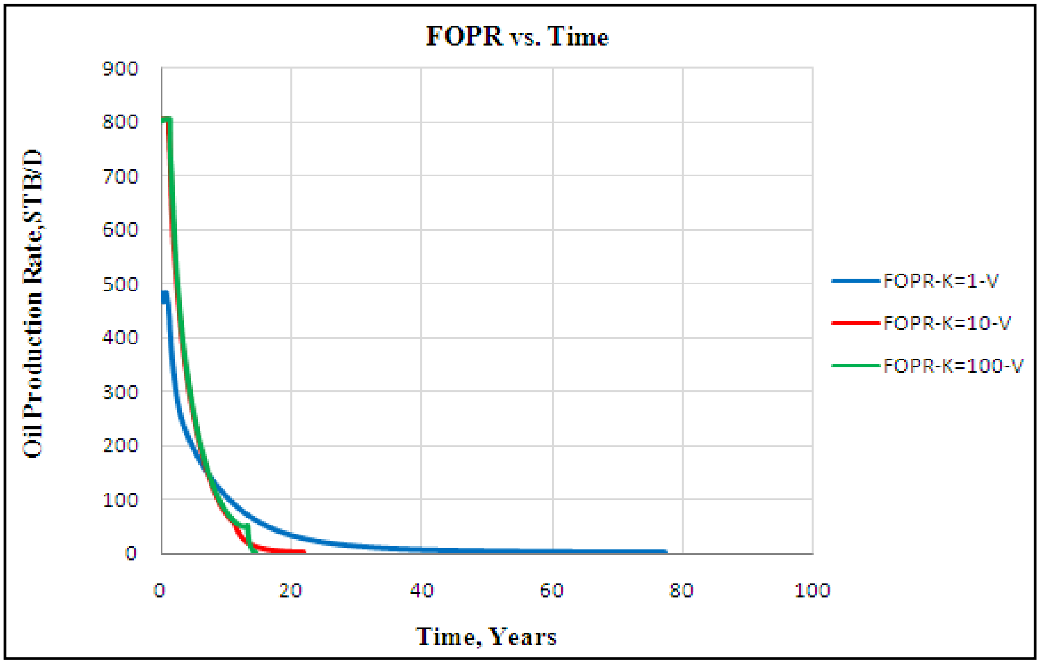

Figure A.35 Oil production rate for vertical wells at A=160 acres, square drainage area and h=100ft

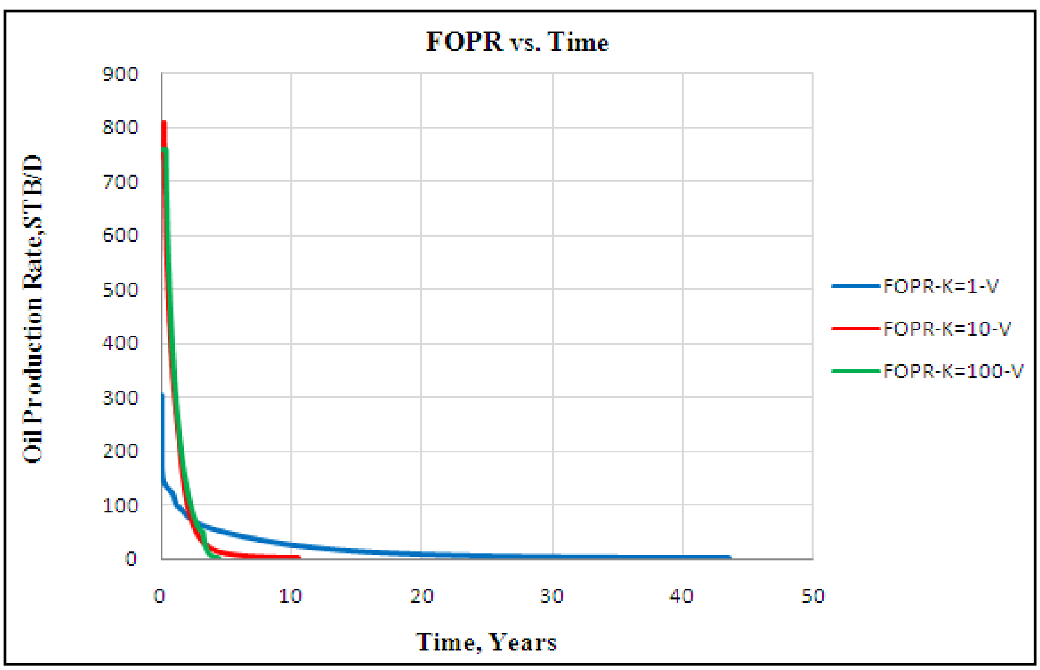

Figure A.36 Oil production rate for vertical wells at A=160 acres, square drainage area and h=25ft

Table A.1 Pressure- recovery factors for vertical well at A=160 acres, square drainage area, h=25ft, k_h=100md and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4364	4159	0.120	0.126	0.125
1.00	3553	3385	0.189	0.249	0.244
1.50	2889	2736	0.232	0.375	0.364
2.00	2320	2162	0.258	0.497	0.479
2.50	1765	1579	0.274	0.623	0.596
3.00	1225	975	0.284	0.746	0.709
3.50	806	700	0.290	0.839	0.795
3.59	782	700	0.291	0.844	0.800
4.38	707	700	0.292	0.860	0.816

Table A.2 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=100md, L_H=2112ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4363	4348	0.121	0.126	0.126
1.00	3551	3538	0.191	0.249	0.244
1.50	2888	2875	0.235	0.375	0.364
2.00	2320	2307	0.261	0.497	0.479
2.50	1764	1750	0.278	0.623	0.597
3.00	1225	1206	0.288	0.746	0.710
3.50	704	700	0.295	0.861	0.816
3.59	700	700	0.295	0.862	0.817

Table A.3 Pressure- recovery factors for vertical well at A=160 acres, square drainage area, h=25ft, k_h=10md and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4374	1462	0.110	0.126	0.125
1.00	3564	1093	0.171	0.249	0.243
1.50	2904	700	0.210	0.373	0.361
2.00	2426	700	0.232	0.475	0.456
2.50	2060	700	0.245	0.557	0.533
3.00	1788	700	0.252	0.619	0.590
3.59	1543	700	0.258	0.674	0.642
4.32	1322	700	0.262	0.725	0.688
4.38	1309	700	0.262	0.728	0.691
10.54	771	700	0.271	0.847	0.801

Table A.4 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H=2112ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4366	4231	0.118	0.126	0.125
1.00	3556	3426	0.184	0.249	0.244
1.50	2892	2766	0.226	0.375	0.363
2.00	2322	2191	0.250	0.497	0.478
2.50	1766	1616	0.266	0.623	0.596
3.50	797	700	0.282	0.841	0.797
3.59	773	700	0.282	0.846	0.802
4.32	706	700	0.283	0.861	0.815

Table A.5 Pressure- recovery factors for vertical well at A=160 acres, square drainage area, h=25ft, k_h =1md and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	5473	700	0.023	0.024	0.024
1.00	5196	700	0.044	0.045	0.045
2.00	4810	700	0.074	0.077	0.077
3.59	4383	700	0.108	0.125	0.124
4.32	4220	700	0.121	0.147	0.145
10.56	3173	700	0.194	0.320	0.310
13.42	2828	700	0.213	0.389	0.375
43.43	1250	700	0.261	0.741	0.703

Table A.6 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1 md, L_H=2112ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	5120	4649	0.051	0.051	0.051
1.00	4596	4095	0.091	0.099	0.099
2.00	3869	3328	0.145	0.200	0.196
2.50	3568	3033	0.163	0.249	0.243
3.00	3291	2761	0.179	0.299	0.290
3.59	2987	2455	0.193	0.358	0.345
4.32	2638	2093	0.207	0.430	0.413
10.54	884	700	0.243	0.822	0.776
13.42	769	700	0.245	0.848	0.800

Table A.7 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h =100md, L_H =2112ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4363	4348	0.121	0.126	0.126
1.00	3551	3538	0.191	0.249	0.244
1.50	2888	2875	0.235	0.375	0.364
2.00	2320	2307	0.261	0.497	0.479
2.50	1764	1750	0.278	0.623	0.597
3.00	1225	1206	0.288	0.746	0.710
3.50	704	700	0.295	0.861	0.816
3.59	700	700	0.295	0.862	0.817

Table A.8 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=100md, L_H=1056ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4363	4328	0.120	0.126	0.125
1.00	3552	3518	0.190	0.249	0.244
1.50	2889	2857	0.233	0.375	0.364
2.00	2320	2287	0.259	0.497	0.479
2.50	1765	1727	0.276	0.623	0.596
3.00	1225	1176	0.286	0.746	0.710
3.59	707	700	0.293	0.860	0.815
3.72	701	700	0.293	0.862	0.817

Table A.9 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=100md, L_H=528ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4364	4302	0.120	0.126	0.125
1.00	3553	3494	0.188	0.249	0.244
1.50	2890	2833	0.231	0.375	0.364
2.00	2321	2261	0.256	0.497	0.479
2.50	1765	1697	0.272	0.623	0.596
3.00	1225	1136	0.282	0.746	0.710
3.59	721	700	0.290	0.857	0.812
3.72	707	700	0.290	0.860	0.815
3.87	702	700	0.290	0.861	0.816

Table A.10 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H =2112ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4366	4231	0.118	0.126	0.125
1.00	3556	3426	0.184	0.249	0.244
1.50	2892	2766	0.226	0.375	0.363
2.00	2322	2191	0.250	0.497	0.478
2.50	1766	1616	0.266	0.623	0.596
3.50	797	700	0.282	0.841	0.797
3.59	773	700	0.282	0.846	0.802
4.32	706	700	0.283	0.861	0.815

Table A.11 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H =1056ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4373	4016	0.112	0.126	0.125
1.00	3564	3213	0.172	0.249	0.243
1.50	2898	2552	0.210	0.375	0.362
2.00	2326	1961	0.232	0.497	0.477
3.00	1234	700	0.254	0.745	0.706
3.59	920	700	0.259	0.814	0.770
3.72	882	700	0.260	0.823	0.778
4.32	782	700	0.261	0.844	0.798
5.53	718	700	0.262	0.858	0.811

Table A.12 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H=528ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4382	3701	0.105	0.126	0.124
1.00	3573	2884	0.159	0.249	0.242
1.50	2903	2212	0.193	0.375	0.361
2.00	2329	1581	0.214	0.497	0.475
2.50	1770	840	0.227	0.623	0.592
3.00	1353	700	0.234	0.718	0.680
3.59	1088	700	0.238	0.777	0.735
3.72	1046	700	0.239	0.787	0.743
3.87	1006	700	0.240	0.796	0.752
4.32	914	700	0.241	0.816	0.770
5.52	788	700	0.243	0.843	0.796
6.94	732	700	0.244	0.856	0.807

Table A.13 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1md, L_H=2112ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	5120	4649	0.051	0.051	0.051
1.00	4596	4095	0.091	0.099	0.099
2.00	3869	3328	0.145	0.200	0.196
2.50	3568	3033	0.163	0.249	0.243
3.00	3291	2761	0.179	0.299	0.290
3.59	2987	2455	0.193	0.358	0.345
4.32	2638	2093	0.207	0.430	0.413
10.54	884	700	0.243	0.822	0.776
13.42	769	700	0.245	0.848	0.800

Table A.14 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1md, L_H =1056ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.50	5158	3894	0.045	0.050	0.050
1.00	4653	3241	0.073	0.100	0.098
1.50	4250	2774	0.094	0.149	0.145
2.00	3918	2385	0.110	0.199	0.192
2.51	3602	2022	0.124	0.250	0.241
3.01	3321	1691	0.134	0.300	0.287
3.59	3018	1303	0.144	0.357	0.341
3.73	2948	1206	0.146	0.371	0.354
4.33	2656	753	0.153	0.431	0.409
5.52	2212	700	0.163	0.526	0.497
13.42	1126	700	0.186	0.769	0.723
19.91	882	700	0.190	0.823	0.773

Table A.15 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=1md, L_H=528ft and k_v/k_h=1

Time	FPR	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.52	5183	2597	0.033	0.051	0.050
1.01	4698	1636	0.052	0.100	0.096
1.52	4273	820	0.068	0.152	0.145
2.01	3964	700	0.080	0.196	0.187
2.50	3717	700	0.091	0.234	0.223
3.02	3497	700	0.101	0.270	0.257
3.59	3286	700	0.110	0.307	0.292
3.72	3240	700	0.112	0.315	0.299
3.86	3196	700	0.114	0.323	0.307
4.32	3054	700	0.120	0.350	0.332
5.52	2742	700	0.133	0.412	0.390
6.93	2446	700	0.145	0.474	0.448
13.43	1626	700	0.170	0.657	0.618
19.90	1233	700	0.180	0.745	0.700
27.21	1003	700	0.185	0.797	0.748

Table A.16 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H =528ft and k_v/k_h=0.5

Time	ARP	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4391	3295	0.097	0.126	0.124
1.00	3579	2447	0.147	0.249	0.241
1.50	2907	1747	0.180	0.375	0.360
2.00	2331	1037	0.201	0.497	0.474
2.50	1828	700	0.213	0.610	0.579
3.00	1512	700	0.220	0.682	0.646
3.59	1265	700	0.225	0.738	0.697
3.72	1222	700	0.226	0.748	0.706
3.87	1178	700	0.227	0.757	0.715
4.32	1070	700	0.229	0.781	0.738
5.52	897	700	0.232	0.820	0.773
6.94	796	700	0.234	0.841	0.793
8.43	747	700	0.235	0.852	0.803

Table A.17 Pressure- recovery factors for horizontal well at A=160acres, square drainage area, h=25ft, k_h=10md, L_H=528ft and k_v/k_h=0.1

Time	ARP	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
1.00	3792	700	0.100	0.218	0.209
1.50	3321	700	0.127	0.298	0.285
2.00	2956	700	0.145	0.367	0.350
2.50	2661	700	0.159	0.427	0.406
3.00	2416	700	0.169	0.480	0.455
3.58	2179	700	0.177	0.532	0.504
4.32	1934	700	0.185	0.587	0.555
6.95	1381	700	0.200	0.712	0.672
8.01	1245	700	0.203	0.743	0.700
8.43	1202	700	0.204	0.752	0.709
10.00	1067	700	0.207	0.782	0.737
13.01	909	700	0.210	0.817	0.769
15.69	830	700	0.212	0.834	0.785

Table A.18 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H=2112ft and k_v/k_h=0.5

Time	ARP	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4370	4128	0.115	0.126	0.125
1.00	3560	3324	0.178	0.249	0.243
1.50	2895	2665	0.217	0.375	0.363
2.00	2324	2083	0.240	0.497	0.478
2.50	1767	1487	0.255	0.623	0.595
3.00	1227	845	0.264	0.746	0.708
3.50	874	700	0.269	0.824	0.780
3.59	848	700	0.269	0.830	0.786
4.00	767	700	0.271	0.848	0.802
4.32	737	700	0.271	0.854	0.808
4.95	711	700	0.271	0.860	0.813

Table A.19 Pressure- recovery factors for horizontal well at A=160 acres, square drainage area, h=25ft, k_h=10md, L_H=2112ft and k_v/k_h=0.1

Time	ARP	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.51	4413	3427	0.091	0.126	0.123
1.00	3601	2554	0.135	0.249	0.240
1.50	2923	1828	0.160	0.375	0.358
2.00	2340	1097	0.174	0.497	0.472
2.50	1842	700	0.183	0.608	0.574
3.00	1548	700	0.187	0.675	0.636
3.59	1313	700	0.191	0.728	0.685
4.00	1197	700	0.193	0.754	0.709
4.32	1122	700	0.194	0.770	0.725
4.95	1014	700	0.196	0.795	0.747
5.50	945	700	0.197	0.810	0.761
6.00	897	700	0.198	0.820	0.771
9.01	757	700	0.200	0.851	0.799

Table A.20 Pressure- recovery factors for horizontal well at A=160acres, square drainage area, h=100ft, k_h=10md, L_H=2112ft and k_v/k_h=0.1

Time	ARP	BHP	ORF	FGRF	GGRF
Years	Psia	Psia	Fraction	Fraction	Fraction
0.50	5355	5047	0.028	0.032	0.031
1.01	4933	4623	0.058	0.064	0.064
1.51	4597	4223	0.082	0.096	0.095
2.00	4343	3947	0.101	0.127	0.125
3.01	3895	3520	0.133	0.191	0.186
3.59	3665	3302	0.148	0.227	0.221
4.32	3397	3045	0.164	0.274	0.265
7.00	2544	2196	0.202	0.444	0.424
9.01	1970	1579	0.218	0.573	0.541
12.01	1159	700	0.230	0.757	0.712
15.00	845	700	0.235	0.826	0.775
18.00	748	700	0.236	0.847	0.794
21.47	711	700	0.236	0.854	0.804

Table A.21 Pressures- recovery factors for all vertical wells cases

Case No.	Area Size	h	K_h	FGRF	GGRF	ORF	ARP	BHP	Time
	acres	ft	md	Fraction	Fraction	Fraction	psia	psia	Years
1	160	100	100	0.858	0.810	0.270	700	700	14.508
2	160	50	100	0.862	0.811	0.279	701	700	7.788
3	160	25	100	0.860	0.816	0.292	707	700	4.380
4	160	100	10	0.854	0.804	0.262	712	700	21.940
5	160	50	10	0.855	0.805	0.266	733	700	14.384
6	160	25	10	0.847	0.801	0.271	771	700	10.540
7	160	100	1	0.819	0.772	0.245	864	700	77.181
8	160	50	1	0.793	0.748	0.252	1008	700	58.960
9	160	25	1	0.741	0.703	0.261	1250	700	43.428
10	80	100	100	0.861	0.807	0.270	702	700	7.268
11	80	50	100	0.860	0.812	0.279	701	700	3.901
12	80	25	100	0.860	0.816	0.291	707	700	2.189
13	80	100	10	0.854	0.807	0.263	712	700	10.841
14	80	50	10	0.853	0.805	0.266	732	700	7.104
15	80	25	10	0.847	0.801	0.270	770	700	5.215
16	80	100	1	0.826	0.776	0.244	858	700	37.324
17	80	50	1	0.795	0.751	0.251	997	700	28.547
18	80	25	1	0.746	0.708	0.261	1228	700	21.120

Table A.22 Pressures- recovery factors for all horizontal wells cases

Case No.	Area Size	h	K_h	K_v/K_h	$L_H/2Xe$	L_H	L_D	FGRF	GGRF	ORF	ARP	BHP	FGPR	Time
	acres	ft	md			ft		Fraction	Fraction	Fraction	psia	psia	MSCF/D	Years
1	160	100	100	1	0.8	2112	10.56	0.858	0.807	0.261	700	700	5000	13.7
2	160	100	100	0.5	0.8	2112	7.47	0.858	0.807	0.261	701	700	5000	13.8
3	160	100	100	0.1	0.8	2112	3.34	0.858	0.807	0.259	700	700	5000	14.4
4	160	50	100	1	0.8	2112	21.12	0.862	0.811	0.283	700	700	5000	7.0
5	160	50	100	0.5	0.8	2112	14.93	0.862	0.811	0.282	700	700	5000	7.1
6	160	50	100	0.1	0.8	2112	6.68	0.862	0.811	0.277	700	700	5000	7.6
7	160	25	100	1	0.8	2112	42.24	0.862	0.817	0.295	700	700	5000	3.6
8	160	25	100	0.5	0.8	2112	29.87	0.862	0.817	0.294	701	700	5000	3.7
9	160	25	100	0.1	0.8	2112	13.36	0.861	0.815	0.284	704	700	5000	4.1
10	160	100	100	1	0.4	1056	5.28	0.858	0.807	0.262	700	700	5000	13.9
11	160	100	100	0.5	0.4	1056	3.73	0.858	0.807	0.262	700	700	5000	14.0
12	160	100	100	0.1	0.4	1056	1.67	0.858	0.807	0.261	700	700	5000	15.0
13	160	50	100	1	0.4	1056	10.56	0.862	0.811	0.280	700	700	5000	7.1
14	160	50	100	0.5	0.4	1056	7.47	0.862	0.811	0.279	700	700	5000	7.3
15	160	50	100	0.1	0.4	1065	3.34	0.862	0.811	0.273	702	700	5000	8.0
16	160	25	100	1	0.4	1056	21.12	0.862	0.817	0.293	701	700	5000	3.7
17	160	25	100	0.5	0.4	1056	14.93	0.861	0.816	0.291	702	700	5000	3.8
18	160	25	100	0.1	0.4	1056	6.68	0.860	0.815	0.280	708	700	5000	4.5
19	160	100	100	1	0.2	528	2.64	0.858	0.807	0.262	701	700	5000	14.103
20	160	100	100	0.5	0.2	528	1.87	0.858	0.807	0.262	700	700	5000	14.355
21	160	100	100	0.1	0.2	528	0.83	0.858	0.807	0.263	700	700	5000	15.755
22	160	50	100	1	0.2	528	5.28	0.862	0.811	0.278	700	700	5000	7.309

Table A.22- Cont'd

23	160	50	100	0.5	0.2	528	3.73	0.862	0.811	0.277	700	700	5000	7.501
24	160	50	100	0.1	0.2	528	1.67	0.862	0.811	0.271	704	700	5000	8.555
25	160	25	100	1	0.2	528	10.56	0.861	0.816	0.290	702	700	5000	3.860
26	160	25	100	0.5	0.2	528	7.47	0.861	0.816	0.288	704	700	5000	4.024
27	160	25	100	0.1	0.2	528	3.34	0.860	0.813	0.275	712	700	5000	4.914
28	160	100	10	1	0.8	2112	10.56	0.858	0.807	0.258	700	700	5000	14.8
29	160	100	10	0.5	0.8	2112	7.47	0.858	0.807	0.256	700	700	5000	15.7
30	160	100	10	0.1	0.8	2112	3.34	0.854	0.804	0.236	711	700	5000	21.5
31	160	50	10	1	0.8	2112	21.12	0.862	0.811	0.276	701	700	5000	7.9
32	160	50	10	0.5	0.8	2112	14.93	0.862	0.811	0.270	704	700	5000	8.6
33	160	50	10	0.1	0.8	2112	6.68	0.855	0.805	0.228	729	700	5000	13.3
34	160	25	10	1	0.8	2112	42.24	0.861	0.815	0.283	706	700	5000	4.3
35	160	25	10	0.5	0.8	2112	29.87	0.860	0.813	0.271	712	700	5000	4.9
36	160	25	10	0.1	0.8	2112	13.36	0.850	0.799	0.200	758	700	5000	9.0
37	160	100	10	1	0.4	1056	5.28	0.858	0.807	0.256	700	700	5000	16.7
38	160	100	10	0.5	0.4	1056	3.73	0.858	0.807	0.253	703	700	5000	18.1
39	160	100	10	0.1	0.4	1056	1.67	0.851	0.801	0.231	723	700	5000	26.3
40	160	50	10	1	0.4	1056	10.56	0.862	0.811	0.264	707	700	5000	9.3
41	160	50	10	0.5	0.4	1056	7.47	0.862	0.811	0.255	713	700	5000	10.4
42	160	50	10	0.1	0.4	1065	3.34	0.855	0.799	0.215	749	700	5000	17.1
43	160	25	10	1	0.4	1056	21.12	0.858	0.811	0.262	718	700	5000	5.5
44	160	25	10	0.5	0.4	1056	14.93	0.856	0.808	0.247	727	700	5000	6.5
45	160	25	10	0.1	0.4	1056	6.68	0.842	0.791	0.193	793	700	5000	12.2
46	160	100	10	1	0.2	528	2.64	0.854	0.807	0.254	705	700	5000	18.9
47	160	100	10	0.5	0.2	528	1.87	0.854	0.804	0.250	718	700	5000	21.1
48	160	100	10	0.1	0.2	528	0.83	0.847	0.798	0.231	741	700	5000	32.7
49	160	50	10	1	0.2	528	5.28	0.862	0.805	0.253	715	700	5000	10.9
50	160	50	10	0.5	0.2	528	3.73	0.855	0.805	0.246	724	700	5000	12.7

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51	160	50	10	0.1	0.2	528	1.67	0.848	0.792	0.220	774	700	5000	21.8
52	160	25	10	1	0.2	528	10.56	0.855	0.807	0.244	732	700	5000	6.9
53	160	25	10	0.5	0.2	528	7.47	0.852	0.803	0.235	748	700	5000	8.4
54	160	25	10	0.1	0.2	528	3.34	0.834	0.785	0.212	831	700	5000	15.7
55	160	100	1	1	0.8	2112	10.56	0.854	0.801	0.244	720	700	3000	32.3
56	160	100	1	0.5	0.8	2112	7.47	0.84	0.797	0.228	747	700	3000	38.22
57	160	100	1	0.1	0.8	2112	3.34	0.819	0.762	0.154	880	700	3000	72.7
58	160	50	1	1	0.8	2112	21.12	0.855	0.805	0.243	739	700	3000	18.5
59	160	50	1	0.5	0.8	2112	14.93	0.848	0.792	0.214	775	700	3000	23.30
60	160	50	1	0.1	0.8	2112	6.68	0.80	0.742	0.132	998	700	3000	49.3
61	160	25	1	1	0.8	2112	42.24	0.848	0.800	0.245	769	700	2000	13.4
62	160	25	1	0.5	0.8	2112	29.87	0.840	0.786	0.210	827	700	2000	16.63
63	160	25	1	0.1	0.8	2112	13.36	0.756	0.705	0.120	1189	700	2000	33.04
64	160	100	1	1	0.4	1056	5.28	0.844	0.791	0.218	760	700	3000	44.1
65	160	100	1	0.5	0.4	1056	3.73	0.836	0.785	0.202	802	700	3000	54.15
66	160	100	1	0.1	0.4	1056	1.67	0.795	0.743	0.179	989	700	3000	103.5
67	160	50	1	1	0.4	1056	10.56	0.841	0.786	0.196	807	700	3000	28.0
68	160	50	1	0.5	0.4	1056	7.47	0.827	0.773	0.180	867	700	3000	36.17
69	160	50	1	0.1	0.4	1056	3.34	0.766	0.716	0.169	1148	700	3000	68.44
70	160	25	1	1	0.4	1056	21.12	0.823	0.773	0.190	883	700	2000	19.9
71	160	25	1	0.5	0.4	1056	14.93	0.803	0.753	0.173	975	700	2000	25.16
72	160	25	1	0.1	0.4	1056	6.67	0.704	0.660	0.152	1419	700	2000	44.23
73	160	100	1	1	0.2	528	2.64	0.833	0.782	0.208	810	700	3000	59.1
74	160	100	1	0.5	0.2	528	1.87	0.822	0.769	0.207	870	700	3000	74.49
75	160	100	1	0.1	0.2	528	0.83	0.771	0.722	0.206	1108	700	3000	134.45
76	160	50	1	1	0.2	528	5.28	0.821	0.767	0.191	884	700	3000	39.1
77	160	50	1	0.5	0.2	528	3.73	0.807	0.745	0.198	963	700	3000	50.1
78	160	50	1	0.1	0.2	528	1.67	0.724	0.685	0.199	1313	700	3000	86.17

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79	160	25	1	1	0.2	528	10.56	0.796	0.748	0.185	1003	700	2000	27.2
80	160	25	1	0.5	0.2	528	7.47	0.770	0.724	0.191	1124	700	2000	34.1
81	160	25	1	0.1	0.2	528	3.34	0.648	0.612	0.193	1667	700	2000	53.62
82	80	100	100	1	0.8	1496	7.48	0.861	0.807	0.260	703	700	5000	6.9
83	80	100	100	0.5	0.8	1496	5.29	0.861	0.807	0.260	704	700	5000	7.0
84	80	100	100	0.1	0.8	1496	2.37	0.861	0.807	0.258	700	700	5000	7.3
85	80	50	100	1	0.8	1496	14.96	0.861	0.813	0.283	700	700	5000	3.6
86	80	50	100	0.5	0.8	1496	10.58	0.860	0.813	0.282	700	700	5000	3.6
87	80	50	100	0.1	0.8	1496	4.73	0.860	0.811	0.275	703	700	5000	4.1
88	80	25	100	1	0.8	1496	29.92	0.862	0.817	0.294	701	700	5000	1.8
89	80	25	100	0.5	0.8	1496	21.16	0.862	0.817	0.292	702	700	5000	1.9
90	80	25	100	0.1	0.8	1496	9.46	0.860	0.814	0.279	710	700	5000	2.3
91	80	100	100	1	0.4	748	3.92	0.861	0.807	0.261	702	700	5000	7.0
92	80	100	100	0.5	0.4	748	2.64	0.861	0.807	0.261	700	700	5000	7.1
93	80	100	100	0.1	0.4	748	1.18	0.861	0.807	0.260	700	700	5000	7.6
94	80	50	100	1	0.4	748	7.48	0.861	0.813	0.280	7	700	5000	3.6
95	80	50	100	0.5	0.4	748	5.29	0.860	0.812	0.279	700	700	5000	3.7
96	80	50	100	0.1	0.4	748	2.37	0.860	0.811	0.271	704	700	5000	4.2
97	80	25	100	1	0.4	748	14.96	0.862	0.817	0.292	702	700	5000	1.9
98	80	25	100	0.5	0.4	748	10.58	0.861	0.816	0.289	703	700	5000	2.0
99	80	25	100	0.1	0.4	748	4.73	0.860	0.813	0.275	712	700	5000	2.4
100	80	100	100	1	0.2	374	1.87	0.861	0.807	0.262	700	700	5000	7.1
101	80	100	100	5	0.2	374	1.32	0.861	0.807	0.262	700	700	5000	7.3
102	80	100	100	0.1	0.2	374	0.59	0.861	0.807	0.262	700	700	5000	8.1
103	80	50	100	1	0.2	374	3.74	0.860	0.813	0.278	700	700	5000	3.7
104	80	50	100	0.5	0.2	374	2.64	0.860	0.812	0.276	701	700	5000	3.8
105	80	50	100	0.1	0.2	374	1.18	0.859	0.810	0.268	707	700	5000	4.5
106	80	25	100	1	0.2	374	7.48	0.861	0.817	0.288	702	700	5000	2.0

Table A.22- Cont’d

107	80	25	100	0.5	0.2	374	5.29	0.861	0.815	0.285	705	700	5000	2.1
108	80	25	100	0.1	0.2	374	2.37	0.859	0.812	0.271	716	700	5000	2.6
109	80	100	10	1	0.8	1496	7.48	0.861	0.807	0.258	696	700	5000	7.6
110	80	100	10	0.5	0.8	1496	5.29	0.861	0.807	0.256	700	700	5000	8.0
111	80	100	10	0.1	0.8	1496	2.37	0.854	0.801	0.236	713	700	5000	11.1
112	80	50	10	1	0.8	1496	14.96	0.860	0.811	0.274	704	700	5000	4.2
113	80	50	10	0.5	0.8	1496	10.58	0.859	0.810	0.266	709	700	5000	4.7
114	80	50	10	0.1	0.8	1496	4.73	0.850	0.797	0.215	752	700	5000	8.2
115	80	25	10	1	0.8	1496	29.92	0.860	0.814	0.277	711	700	5000	2.4
116	80	25	10	0.5	0.8	1496	21.16	0.858	0.811	0.262	721	700	5000	2.8
117	80	25	10	0.1	0.8	1496	9.46	0.840	0.788	0.188	808	700	5000	5.6
118	80	100	10	1	0.4	748	3.92	0.861	0.807	0.255	700	700	5000	8.5
119	80	100	10	0.5	0.4	748	2.64	0.861	0.807	0.253	704	700	5000	9.3
120	80	100	10	0.1	0.4	748	1.18	0.854	0.801	0.231	726	700	5000	13.6
121	80	50	10	1	0.4	748	7.48	0.858	0.809	0.262	710	700	5000	4.9
122	80	50	10	0.5	0.4	748	5.29	0.857	0.807	0.251	717	700	5000	5.6
123	80	50	10	0.1	0.4	748	2.37	0.846	0.793	0.204	768	700	5000	9.9
124	80	25	10	1	0.4	748	14.96	0.858	0.810	0.257	722	700	5000	3.0
125	80	25	10	0.5	0.4	748	10.58	0.855	0.806	0.239	735	700	5000	3.5
126	80	25	10	0.1	0.4	748	4.73	0.835	0.783	0.182	829	700	5000	6.9
127	80	100	10	1	0.2	374	1.87	0.861	0.807	0.254	705	700	5000	9.9
128	80	100	10	5	0.2	374	1.32	0.854	0.801	0.250	713	700	5000	11.2
129	80	100	10	0.1	0.2	374	0.59	0.847	0.795	0.232	748	700	5000	17.6
130	80	50	10	1	0.2	374	3.74	0.856	0.806	0.249	720	700	5000	5.9
131	80	50	10	0.5	0.2	374	2.64	0.854	0.803	0.240	731	700	5000	6.9
132	80	50	10	0.1	0.2	374	1.18	0.840	0.788	0.208	795	700	5000	12.3
133	80	25	10	1	0.2	374	7.48	0.854	0.805	0.239	739	700	5000	3.8
134	80	25	10	0.5	0.2	374	5.29	0.850	0.801	0.227	757	700	5000	4.6

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135	80	25	10	0.1	0.2	374	2.37	0.828	0.778	0.200	862	700	5000	8.7
136	80	100	1	1	0.8	1496	7.48	0.854	0.801	0.243	725	700	3000	16.9
137	80	50	1	1	0.8	1496	14.96	0.848	0.798	0.247	759	700	3000	12.7
138	80	25	1	1	0.8	1496	29.92	0.839	0.791	0.231	807	700	2000	7.6
139	80	100	1	1	0.4	748	3.92	0.847	0.788	0.219	766	700	3000	22.9
140	80	50	1	1	0.4	748	7.48	0.834	0.783	0.211	823	700	3000	16.6
141	80	25	1	1	0.4	748	14.96	0.817	0.766	0.184	913	700	2000	10.7
142	80	100	1	1	0.2	374	1.87	0.833	0.776	0.209	827	700	3000	31.7
143	80	50	1	1	0.2	374	3.74	0.814	0.763	0.196	915	700	3000	22.0
144	80	25	1	1	0.2	374	7.48	0.787	0.738	0.178	1051	700	2000	14.7

Table A.23 Recovery factors ratio and time ratio for all horizontal and vertical wells cases

Case No.	Area Size	h	K_h	K_v/K_h	$L_H/2Xe$	L_H	FG_H/FG_V	GG_H/GG_V	OR_H/OR_V	t_V/t_H	Recommended Well Type
	acres	ft	md			ft					
1	160	100	100	1	0.8	2112	1.000	0.996	0.967	1.059	Vertical well
2	160	100	100	0.5	0.8	2112	1.000	0.996	0.967	1.051	Vertical well
3	160	100	100	0.1	0.8	2112	1.000	0.996	0.960	1.008	Vertical well
4	160	50	100	1	0.8	2112	1.000	1.000	1.014	1.113	Vertical well
5	160	50	100	0.5	0.8	2112	1.000	1.000	1.011	1.097	Vertical well
6	160	50	100	0.1	0.8	2112	1.000	1.000	0.993	1.025	Vertical well
7	160	25	100	1	0.8	2112	1.002	1.002	1.012	1.217	Vertical well
8	160	25	100	0.5	0.8	2112	1.002	1.002	1.008	1.184	Vertical well
9	160	25	100	0.1	0.8	2112	1.001	0.999	0.974	1.068	Vertical well
10	160	100	100	1	0.4	1056	1.000	0.996	0.971	1.044	Vertical well
11	160	100	100	0.5	0.4	1056	1.000	0.996	0.971	1.036	Vertical well
12	160	100	100	0.1	0.4	1056	1.000	0.996	0.967	0.967	Vertical well
13	160	50	100	1	0.4	1056	1.000	1.000	1.003	1.097	Vertical well
14	160	50	100	0.5	0.4	1056	1.000	1.000	1.000	1.067	Vertical well
15	160	50	100	0.1	0.4	1065	1.000	1.000	0.978	0.974	Vertical well
16	160	25	100	1	0.4	1056	1.002	1.002	1.005	1.184	Vertical well
17	160	25	100	0.5	0.4	1056	1.001	1.001	0.998	1.153	Vertical well
18	160	25	100	0.1	0.4	1056	1.000	0.999	0.960	0.973	Vertical well
19	160	100	100	1	0.2	528	1.000	0.996	0.971	1.029	Vertical well
20	160	100	100	0.5	0.2	528	1.000	0.996	0.971	1.011	Vertical well
21	160	100	100	0.1	0.2	528	1.000	0.996	0.975	0.921	Vertical well

Table A.23- Cont'd

22	160	50	100	1	0.2	528	1.000	1.000	0.996	1.066	Vertical well
23	160	50	100	0.5	0.2	528	1.000	1.000	0.993	1.038	Vertical well
24	160	50	100	0.1	0.2	528	1.000	1.000	0.971	0.910	Vertical well
25	160	25	100	1	0.2	528	1.001	1.001	0.994	1.135	Vertical well
26	160	25	100	0.5	0.2	528	1.001	1.001	0.988	1.088	Vertical well
27	160	25	100	0.1	0.2	528	1.000	0.997	0.943	0.891	Vertical well
28	160	100	10	1	0.8	2112	1.004	1.004	0.983	1.482	Horizontal well
29	160	100	10	0.5	0.8	2112	1.004	1.004	0.976	1.397	Horizontal well
30	160	100	10	0.1	0.8	2112	1.000	1.000	0.899	1.020	Vertical well
31	160	50	10	1	0.8	2112	1.008	1.008	1.037	1.821	Horizontal well
32	160	50	10	0.5	0.8	2112	1.008	1.008	1.014	1.673	Horizontal well
33	160	50	10	0.1	0.8	2112	1.000	1.000	0.856	1.082	Vertical well
34	160	25	10	1	0.8	2112	1.017	1.017	1.046	2.451	Horizontal well
35	160	25	10	0.5	0.8	2112	1.016	1.015	1.002	2.151	Horizontal well
36	160	25	10	0.1	0.8	2112	1.004	0.997	0.739	1.171	Vertical well
37	160	100	10	1	0.4	1056	1.004	1.004	0.976	1.314	Horizontal well
38	160	100	10	0.5	0.4	1056	1.004	1.004	0.964	1.212	Horizontal well
39	160	100	10	0.1	0.4	1056	0.996	0.996	0.880	0.834	Vertical well
40	160	50	10	1	0.4	1056	1.008	1.008	0.992	1.547	Horizontal well
41	160	50	10	0.5	0.4	1056	1.008	1.008	0.958	1.383	Horizontal well
42	160	50	10	0.1	0.4	1065	1.000	0.993	0.808	0.841	Vertical well
43	160	25	10	1	0.4	1056	1.014	1.012	0.968	1.916	Horizontal well
44	160	25	10	0.5	0.4	1056	1.011	1.009	0.913	1.622	Horizontal well
45	160	25	10	0.1	0.4	1056	0.995	0.987	0.713	0.864	Vertical well

Table A.23- Cont'd

46	160	100	10	1	0.2	528	1.000	1.004	0.968	1.161	Vertical well
47	160	100	10	0.5	0.2	528	1.000	1.000	0.953	1.040	Vertical well
48	160	100	10	0.1	0.2	528	0.992	0.993	0.880	0.671	Vertical well
49	160	50	10	1	0.2	528	1.008	1.000	0.950	1.320	Horizontal well
50	160	50	10	0.5	0.2	528	1.000	1.000	0.924	1.133	Vertical well
51	160	50	10	0.1	0.2	528	0.992	0.984	0.826	0.660	Vertical well
52	160	25	10	1	0.2	528	1.010	1.007	0.902	1.528	Horizontal well
53	160	25	10	0.5	0.2	528	1.006	1.002	0.869	1.255	Horizontal well
54	160	25	10	0.1	0.2	528	0.985	0.980	0.784	0.671	Vertical well
55	160	100	1	1	0.8	2112	1.042	1.037	0.995	2.390	Horizontal well
56	160	100	1	0.5	0.8	2112	1.025	1.032	0.930	2.019	Horizontal well
57	160	100	1	0.1	0.8	2112	0.999	0.987	0.628	1.062	Vertical well
58	160	50	1	1	0.8	2112	1.078	1.076	0.965	3.187	Horizontal well
59	160	50	1	0.5	0.8	2112	1.069	1.058	0.850	2.530	Horizontal well
60	160	50	1	0.1	0.8	2112	1.009	0.992	0.524	1.196	Vertical well
61	160	25	1	1	0.8	2112	1.145	1.138	0.938	3.241	Horizontal well
62	160	25	1	0.5	0.8	2112	1.134	1.118	0.804	2.611	Horizontal well
63	160	25	1	0.1	0.8	2112	1.020	1.002	0.460	1.314	Vertical well
64	160	100	1	1	0.4	1056	1.030	1.024	0.889	1.750	Horizontal well
65	160	100	1	0.5	0.4	1056	1.020	1.017	0.824	1.425	Horizontal well
66	160	100	1	0.1	0.4	1056	0.970	0.962	0.730	0.746	Vertical well
67	160	50	1	1	0.4	1056	1.060	1.050	0.778	2.106	Horizontal well
68	160	50	1	0.5	0.4	1056	1.043	1.033	0.715	1.630	Horizontal well
69	160	50	1	0.1	0.4	1056	0.966	0.957	0.671	0.861	Vertical well

Table A.23- Cont'd

70	160	25	1	1	0.4	1056	1.111	1.099	0.728	2.182	Horizontal well
71	160	25	1	0.5	0.4	1056	1.084	1.071	0.663	1.726	Horizontal well
72	160	25	1	0.1	0.4	1056	0.950	0.938	0.582	0.982	Vertical well
73	160	100	1	1	0.2	528	1.017	1.013	0.848	1.306	Horizontal well
74	160	100	1	0.5	0.2	528	1.003	0.996	0.844	1.036	Vertical well
75	160	100	1	0.1	0.2	528	0.941	0.935	0.840	0.574	Vertical well
76	160	50	1	1	0.2	528	1.035	1.025	0.758	1.508	Horizontal well
77	160	50	1	0.5	0.2	528	1.018	0.996	0.786	1.177	Horizontal well
78	160	50	1	0.1	0.2	528	0.913	0.915	0.790	0.684	Vertical well
79	160	25	1	1	0.2	528	1.074	1.064	0.709	1.597	Horizontal well
80	160	25	1	0.5	0.2	528	1.039	1.029	0.732	1.274	Horizontal well
81	160	25	1	0.1	0.2	528	0.875	0.870	0.739	0.810	Vertical well
82	80	100	100	1	0.8	1496	1.000	0.999	0.964	1.053	Vertical well
83	80	100	100	0.5	0.8	1496	1.000	0.999	0.964	1.038	Vertical well
84	80	100	100	0.1	0.8	1496	1.000	0.999	0.957	0.996	Vertical well
85	80	50	100	1	0.8	1496	1.001	1.001	1.015	1.084	Vertical well
86	80	50	100	0.5	0.8	1496	1.000	1.001	1.012	1.084	Vertical well
87	80	50	100	0.1	0.8	1496	1.000	0.998	0.987	0.951	Vertical well
88	80	25	100	1	0.8	1496	1.002	1.002	1.012	1.216	Vertical well
89	80	25	100	0.5	0.8	1496	1.002	1.002	1.005	1.152	Vertical well
90	80	25	100	0.1	0.8	1496	0.999	0.998	0.960	0.952	Vertical well
91	80	100	100	1	0.4	748	1.000	0.999	0.968	1.038	Vertical well
92	80	100	100	0.5	0.4	748	1.000	0.999	0.968	1.024	Vertical well
93	80	100	100	0.1	0.4	748	1.000	0.999	0.964	0.956	Vertical well

Table A.23- Cont'd

94	80	50	100	1	0.4	748	1.001	1.001	1.005	1.084	Vertical well
95	80	50	100	0.5	0.4	748	1.000	1.000	1.001	1.054	Vertical well
96	80	50	100	0.1	0.4	748	1.000	0.998	0.972	0.929	Vertical well
97	80	25	100	1	0.4	748	1.002	1.002	1.005	1.152	Vertical well
98	80	25	100	0.5	0.4	748	1.001	1.001	0.995	1.095	Vertical well
99	80	25	100	0.1	0.4	748	0.999	0.997	0.946	0.912	Vertical well
100	80	100	100	1	0.2	374	1.000	0.999	0.971	1.024	Vertical well
101	80	100	100	5	0.2	374	1.000	0.999	0.971	0.996	Vertical well
102	80	100	100	0.1	0.2	374	1.000	0.999	0.971	0.897	Vertical well
103	80	50	100	1	0.2	374	1.000	1.001	0.997	1.054	Vertical well
104	80	50	100	0.5	0.2	374	1.000	1.000	0.990	1.026	Vertical well
105	80	50	100	0.1	0.2	374	0.999	0.997	0.962	0.867	Vertical well
106	80	25	100	1	0.2	374	1.001	1.002	0.991	1.095	Vertical well
107	80	25	100	0.5	0.2	374	1.001	0.999	0.981	1.043	Vertical well
108	80	25	100	0.1	0.2	374	0.998	0.996	0.933	0.842	Vertical well
109	80	100	10	1	0.8	1496	1.008	0.999	0.982	1.426	Horizontal well
110	80	100	10	0.5	0.8	1496	1.008	0.999	0.974	1.355	Horizontal well
111	80	100	10	0.1	0.8	1496	1.000	0.992	0.898	0.977	Vertical well
112	80	50	10	1	0.8	1496	1.008	1.007	1.031	1.691	Horizontal well
113	80	50	10	0.5	0.8	1496	1.007	1.006	1.001	1.511	Horizontal well
114	80	50	10	0.1	0.8	1496	0.996	0.990	0.809	0.866	Vertical well
115	80	25	10	1	0.8	1496	1.016	1.016	1.025	2.173	Horizontal well
116	80	25	10	0.5	0.8	1496	1.013	1.012	0.969	1.862	Horizontal well
117	80	25	10	0.1	0.8	1496	0.992	0.983	0.696	0.931	Vertical well

Table A.23- Cont'd

118	80	100	10	1	0.4	748	1.008	0.999	0.970	1.275	Horizontal well
119	80	100	10	0.5	0.4	748	1.008	0.999	0.963	1.166	Horizontal well
120	80	100	10	0.1	0.4	748	1.000	0.992	0.879	0.797	Vertical well
121	80	50	10	1	0.4	748	1.005	1.005	0.986	1.450	Horizontal well
122	80	50	10	0.5	0.4	748	1.004	1.002	0.945	1.269	Horizontal well
123	80	50	10	0.1	0.4	748	0.991	0.985	0.768	0.718	Vertical well
124	80	25	10	1	0.4	748	1.013	1.011	0.951	1.738	Horizontal well
125	80	25	10	0.5	0.4	748	1.010	1.006	0.884	1.490	Horizontal well
126	80	25	10	0.1	0.4	748	0.986	0.977	0.673	0.756	Vertical well
127	80	100	10	1	0.2	374	1.008	0.999	0.967	1.095	Vertical well
128	80	100	10	5	0.2	374	1.000	0.992	0.951	0.968	Vertical well
129	80	100	10	0.1	0.2	374	0.992	0.985	0.883	0.616	Vertical well
130	80	50	10	1	0.2	374	1.003	1.001	0.937	1.204	Vertical well
131	80	50	10	0.5	0.2	374	1.001	0.998	0.903	1.030	Vertical well
132	80	50	10	0.1	0.2	374	0.984	0.979	0.783	0.578	Vertical well
133	80	25	10	1	0.2	374	1.008	1.004	0.884	1.372	Horizontal well
134	80	25	10	0.5	0.2	374	1.004	0.999	0.840	1.134	Vertical well
135	80	25	10	0.1	0.2	374	0.978	0.971	0.740	0.599	Vertical well
136	80	100	1	1	0.8	1496	1.033	1.032	0.996	2.209	Horizontal well
137	80	50	1	1	0.8	1496	1.066	1.063	0.986	2.248	Horizontal well
138	80	25	1	1	0.8	1496	1.125	1.118	0.886	2.779	Horizontal well
139	80	100	1	1	0.4	748	1.025	1.016	0.898	1.630	Horizontal well
140	80	50	1	1	0.4	748	1.048	1.043	0.842	1.720	Horizontal well
141	80	25	1	1	0.4	748	1.096	1.082	0.706	1.974	Horizontal well

Table A.23- Cont'd

142	80	100	1	1	0.2	374	1.008	1.000	0.857	1.177	Horizontal well
143	80	50	1	1	0.2	374	1.023	1.016	0.782	1.298	Horizontal well
144	80	25	1	1	0.2	374	1.055	1.043	0.683	1.437	Horizontal well

VITA

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